BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Analysis of IOUs' Hedging Practices	Docket No. 20170057-EI Filed: August 10, 2017

Direct Testimony of Elizabeth A. Stanton

On Behalf of Sierra Club

August 10, 2017

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Exhibit EAS-12 Weston Berg, et al., American Council for an Energy-Efficient Economy, *The 2016 State Energy Efficiency Scorecard* (September 2016).

Exhibit EAS-13 Jacksonville Electric Authority, *2015 Solar RFP – Phase 2 Summary*, June 10, 2015, *available at* https://www.jea.com/About/Procurement/Bid_Results/Solar_2015_-_June_11,_2015.aspx.

Exhibit EAS-14 U.S. Department of Energy, *Q4 2016/Q1 2017 Solar Industry Update*, April 25, 2017, *available at* http://www.nrel.gov/docs/fy17osti/68425.pdf.

I. IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name, position, and business address.

A. My name is Elizabeth A. Stanton, PhD. I am the Director and Senior Economist of the Applied Economics Clinic, 44 Teele Avenue, Somerville, Massachusetts 02144.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Sierra Club.

Q. Have you previously testified before the Florida Public Service Commission?

A. No.

Q. Please summarize your professional and educational experience, and attach a current copy of your curriculum vitae.

A. I am an economist with more than 16 years of experience conducting research and analysis on behalf of a variety of government and non-governmental clients. I have authored more than 120 reports, policy studies, white papers, journal articles, and book chapters on topics related to energy and the economy. I currently serve as the Director of the Applied Economics Clinic, a non-profit consultancy focused on the electric sector and housed at Tufts University. The Applied Economics Clinic provides expert testimony, analysis, modeling, policy briefs, and reports for groups on the topics of energy, environment, consumer protection, and equity.

In my previous position as a Principal Economist at Synapse Energy Economics, I led studies examining cost-benefit analyses and environmental regulation. I have submitted expert testimony and comments in Illinois, Vermont, New Hampshire, Massachusetts, and several federal dockets.

I earned my Ph.D. in economics at the University of Massachusetts-Amherst, and have taught economics at Tufts University, the University of Massachusetts-Amherst, and the College of New Rochelle, among other schools. My curriculum vitae is attached to this testimony as Exhibit EAS-1.

II. INTRODUCTION AND SUMMARY OF TESTIMONY

Q. What are the topics of your testimony?

A. My testimony focuses on Issue 2 in this docket: "Is it in the consumers' best interest for the utilities to continue natural gas financial hedging activities?"[1] Specifically, I discuss the important role that generation diversity plays in reducing ratepayer exposure to volatility in fuel markets. I review current and historical generation diversity in Florida and present an illustrative "what if" analysis detailing what would have happened if the extra $6.9 billion of ratepayer money spent on financial hedging had instead been invested in renewables and energy efficiency.

Q. What are your overall conclusions?

A. I conclude that Florida's investor owned utilities (IOUs) could effectively limit their exposure to volatile natural gas markets by diversifying their resource mixes to include more renewables and by decreasing electricity demand through energy efficiency investments. My conclusion is based on a simple illustrative analysis that

[1] Order No. PSC-17-0239-PCO-EI at 4.

considers the impact of investing the $6.9 billion in ratepayer dollars lost on financial hedges over the past ten years in solar and energy efficiency over the same period; a review of relevant literature; and my own knowledge and expertise.

While generation diversity is a well-accepted method of reducing consumer's exposure to fuel price volatility, the IOUs have not evaluated its viability as a risk reducing measure. Indeed, Florida's resource mix is notably less diverse than most other U.S. states. In 2016, Florida derived 66 percent of its electricity from natural gas, compared to a national average of 43 percent.[2] Florida's natural gas reliance was greater than that of all but four states, two of which are members of larger regional grid operators and therefore have access to electricity from a more diverse set of generators.[3]

Since 1990, Florida's utilities have quintupled their investment in natural gas generating capacity from 8,613 to 45,487 megawatts (MW). In 2016, Florida had 45,487 MW of natural gas capacity and only 330 MW of solar. That is 137 MW of gas for every 1 MW of solar. Yet, Florida has an enormous latent potential to build out its solar generation and reduce demand through energy efficiency. My simple analysis illustrates the important benefits to ratepayers of doing so. Specifically, my analysis indicates that ratepayers would have reduced their dependence on natural gas by approximately 8 percent and saved a corresponding $6.6 billion in avoided fuel costs had the IOUs spent the money they lost on financial hedges on renewables and energy efficiency instead.

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[2] *See infra* Section IV.
[3] *See infra* Figure 3.

Q. What sources have you relied upon in this testimony?

A. I have focused on the IOUs filings related to annual hedging losses as well as government and industry publications related to fuel price volatility. I have referenced the sources relied upon in my testimony and/or attached these sources as exhibits.

III. FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings in this case.

A. Based on the information that I reviewed in this docket, the Florida specific analysis that I present below, my relevant experience and knowledge, and review of professional literature on fuel price volatility and risk reducing measures, my findings are as follows:

1. Solar and energy efficiency improve generation diversity and thereby help reduce fuel price volatility and save customers money;
2. The IOUs have dramatically increased their investments in natural gas generation while pursuing very low levels of investment in renewables and energy efficiency;
3. Greater investments in solar and energy efficiency, over the past ten years, would have yielded extensive customer savings;
4. The IOUs' failure to diversify their resource mix now renders their customers more exposed to natural gas price volatility than customers in most other states; and

5. To reduce exposure to natural gas price volatility, the IOUs should instead evaluate and pursue generation diversity, especially through added solar and energy efficiency.

Q. What are your recommendations to this Commission?

A. Based on these findings, I recommend that the Commission find that continuing the exclusive use of financial hedges to control customer exposure to natural gas price volatility is not in the consumers' best interest. The Commission should not reauthorize the use of financial hedges until it is presented with a detailed assessment of alternative ways to limit the risk from fuel price volatility. Solar generation provides electricity without any fuel costs and efficiency reduces the amount of natural gas required. As such these resources reduce ratepayers' vulnerability to fluctuations in natural gas prices.

IV. GENERATION DIVERSITY IS A STANDARD MEASURE TAKEN TO REDUCE THE RISK OF FUEL PRICE VOLATILITY

Q. What is fuel price volatility?

A. Fuel price volatility is the degree to which fuel prices change over time. A volatile fuel price is one that experiences relatively large changes over relatively short periods of time (in contrast to a price that remains at a steady level or changes at a steady, gradual rate). More formally, as defined by the U.S. Energy Information Administration (EIA):

> The term "price volatility" is used to describe price fluctuations of a commodity. Volatility is measured by the day-to-day percentage difference

> in the price of the commodity. Volatility provides a measure of price uncertainty in markets.[4]

Q. What are the impacts of fuel price volatility?

A. Volatile fuel prices expose electric consumers to unplanned periods of high prices that often coincide with periods of high electric demand. EIA's definition of fuel price volatility continues:

> When volatility rises, firms may delay investment and other decisions or increase their risk management activities. The costs associated with such activities tend to increase the costs of supplying and consuming gas.[5]

Q. What factors increase exposure to fuel price volatility and the severity of its impacts?

A. Many factors influence exposure to fuel price volatility. The main factor within the IOUs control is the degree of their reliance on a single volatile fuel for generating electricity. As the EIA acknowledges, "the natural gas market is subject to significant fluctuations in the level of volatility."[6] Increased reliance on natural gas therefore increases exposure to volatility. An electric utility that relies on natural gas for 100 percent of its owned or contracted generation has a greater exposure to unplanned periods of high gas prices than does an electric utility that is only reliant on gas for 10 percent of its generation.

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[4] *Natural Gas Weekly Update Archive* (Oct. 22, 2003), U.S. Energy and Information Administration, https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2003/10_23/.
[5] *Id*.
[6] *Id*.

Q. Have natural gas prices faced by Florida's electric generators been volatile?

A. Yes, gas prices in Florida track national trends which have historically exhibited high levels of volatility.

Figure 1. Henry Hub Natural Gas Spot Prices (2016)[7]

In addition, the EIA acknowledges past volatility in the price of natural gas and incorporates volatility into its projections of future gas prices.[8]

Q. Are future natural gas prices expected to continue to demonstrate volatility?

[7] Figure 1 was derived from EIA data. FPL Witness Gerard J. Yupp produces an essentially identical graph in his testimony. *See* Exhibit GJY-1.

[8] U.S. Energy Information Administration, *Short-Term Energy Outlook Supplement: Energy Price Volatility and Forecast Uncertainty* (Oct. 2009), https://www.eia.gov/outlooks/steo/special/pdf/2009_sp_05.pdf.

A. Yes. Natural gas prices are expected to continue to exhibit volatile characteristics. Utility trade groups have acknowledged that "natural gas prices continue to be hard to predict, prone to multiyear cycles, strongly seasonal, and capable of significant spikes. The root causes of these price dynamics are not going away anytime soon."[9]

Q. What measures have the IOUs taken to manage gas price volatility?

A. According to the Commission's 2002 Hedging Order, PSC-02-1484-FOF-EI, Florida's utilities have used financial mechanisms to reduce exposure to natural gas price volatility. The evolution of financial hedging natural gas prices in Florida is described in further detail in the testimony of Staff witness Mark Anthony Cicchetti filed in Docket No. 16001-EI.

Q. How much have Florida's utilities lost on these risk-reducing measures over the past ten years?

A. From 2007 through 2016 FPL, DEF, and TECO lost a net $6.9 billion on financial hedging mechanisms.[10]

Q. What measures do the IOUs propose to manage gas price volatility in the future?

A. DEF, FPL and TECO have proposed to continue relying on financial mechanisms to hedge against the risk of natural gas price increases. While the mechanics of their

[9] Lawrence Makovich, et al., *The Value of U.S. Power Supply Diversity*. IHS Energy at 6 (July 2014), http://www.energyxxi.org/sites/default/files/USPowerSupplyDiversityStudy.pdf. Attached hereto as Exhibit EAS-2.

[10] Data derived from the IOUs responses to Sierra Club's First Set of Interrogatories, Interrogatory No. 4.

proposed approach are still undefined further description is available in the IOUs' direct testimony presented in this docket.[11]

Q. How does financial hedging impact ratepayers?

A. Financial hedges expose ratepayers to increased costs with only a limited benefit. While the practice of natural gas price hedging insures against the risk of unexpectedly high costs, it creates its own set of risks and passes on additional costs to the ratepayers. In doing so, it may lessen the incentive for the IOUs to take other prudent actions to reduce fuel price exposure.

In a 2003 article in *Utilities Policy*, Ken Costello of the National Regulatory Research Institute (which was founded by the National Association of Regulatory Utility Commissioners) described this flaw in fuel price hedging as a "moral hazard." Costello explains that utility commissions' approval of hedging expenses "would exonerate a utility from accountability for its actions in executing a [] hedging plan [thus approved by the commission]. In effect, opponents of [commissions' advanced approval of hedging plans] have argued that firming a commission's commitment up-front to a particular hedging plan may magnify the incentive (moral hazard) problem arising from the principal-agent relationship between a commission and a utility." In other words, because the utilities have more information than do utility commissions about fuel prices and their risks, hedging puts the utilities in the position to request

[11] *See generally* Direct Testimony of Joseph McCallister, Docket No. 20170057; Direct Testimony of Gerard J. Yupp, Docket No. 20170057, Direct Testimony of J. Brent Caldwell, Docket No. 20170057.

and receive approval for actions (such as investment in new natural gas generating resources) that may benefit the utilities' shareholders but not their ratepayers.[12]

Essentially, as long as the price of gas is hedged, utilities have little incentive to invest in resource diversity or otherwise protect customers from fuel price spikes. Hedging stabilizes effective fuel prices and the IOUs benefit from that stability without having to worry about the price paid for such certainty. The cost of hedging is ultimately borne by the ratepayers and will not impact directly on the utilities' bottom lines or their stockholders' returns.

Q. Are other measures available to reduce ratepayers' exposure to risk from fuel price volatility?

A. Yes, the risks and impacts of fuel price volatility can be limited by enhancing generation diversity. Generation diversity is a "hedge" against fuel price volatility.

Q. How does generation diversity reduce customer exposure to fuel price volatility?

A. Enhanced generation diversity and reduced reliance on fuels with volatile prices reduce risk and limit potential impacts of unforeseen spikes in natural gas prices. Increased diversity reduces the gross amount of any single fuel purchased by the utility. Diversification has been acknowledged as a successful tool for limiting risk.

Regulators and utilities should pursue diversification of utility portfolios, adding energy efficiency, demand response, and renewable energy resources to the

[12] Ken Costello, *Should commissions pre-approve a gas utility's hedging activities?*, 11 Utilities Policy 185, 185 (2003). Attached hereto as Exhibit EAS-3.

portfolio mix. Including a mix of supply and demand-side resources, distributed and centralized resources, and fossil and non-fossil generation provides important risk management benefits to resource portfolios because each type of resource behaves independently from the others in different future scenarios. In the other direction, failing to diversify resources, "betting the farm" on a narrow set of large resources, and ignoring potentially disruptive future scenarios is asking for trouble.[13]

Q. Have other jurisdictions acknowledged the role that diversity plays in insulating customers from volatile fuel markets?

A. Yes, for example PJM and New York ISO[14] have both released analyses on the risks of over reliance on a single fuel. PJM's 2017 Evolving Resource Mix and System Reliability Report explains that generation and fuel diversity mitigate the risk associated with design failures, address fuel price volatility and fuel supply disruptions, and insulate against instability from weather and supply-side shocks.

> PJM recognizes that the benefits of fuel mix diversity include the ability to withstand equipment design issues or common modes of failure in similar

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[13] Ronald J. Binz, et al., CERES, *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know* at 12 (April 2012) *available at* http://www.raponline.org/wp-content/uploads/2016/05/ceres-binzsedano-riskawareregulation-2012-apr-19.pdf. Attached as Exhibit EAS-4.

[14] PJM is the regional transmission organization (RTO) overseeing wholesale electricity markets across Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and D.C. *Who We Are*, PJM.com, http://www.pjm.com/about-pjm/who-we-are.aspx. The New York Independent System Operator (ISO) manages the flow of wholesale electricity throughout New York State. *About NYISO*, New York Independent System Operator, https://home.nyiso.com/.

> resource types, fuel price volatility, fuel supply disruptions and other unforeseen system shocks…
>
> Fuel diversity in the electric system generally is defined as utilizing multiple resource types to meet demand. A more diversified system is intuitively expected to have increased flexibility and adaptability to: 1) mitigate risk associated with equipment design issues or common modes of failure in similar resource types, 2) address fuel price volatility and fuel supply disruptions, and 3) reliably mitigate instabilities caused by weather and other unforeseen system shocks. In this way, fuel diversity can be considered a system-wide hedging tool that helps ensure a stable, reliable supply of electricity.[15]

Similarly, a 2008 study of fuel diversity by the New York ISO and Analysis Group concluded that increased generation diversity leads to less price volatility and improved reliability:

> Maintaining and improving fuel diversity in New York will likely to lead to less volatile electric prices, improved reliability and positive environmental impacts. It is essential that public policy makers and the NYISO confront the risks that are posed by inadequate fuel diversity. Market forces should be harnessed and planning principles should be utilized to encourage signals that will lead to support for the protocols and

[15] PJM Interconnection, *PJM's Evolving Resource Mix and System Reliability* at 6-8 (March 30, 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx. Attached hereto as Exhibit EAS-5.

technologies necessary to move New York towards an optimum fuel diversity profile.[16]

Q. Have the risk reducing benefits of generation diversity been acknowledged by governmental institutions?

A. Yes. As a 2015 study published by the Lawrence Berkeley National Laboratory and U.S. Department of Energy states "by offering flat or even declining prices in real dollar terms over long periods of time, solar (and wind) power can provide long-term hedge against the risk of rising fossil fuel prices."[17]

In 2008, a study by the Commission for Environmental Cooperation—a collaborative, intergovernmental organization representing the United States, Canada and Mexico—described the potential for renewable energy to serve as a financial "hedge" reducing exposure to fuel price risk.

> In a time of fuel price fluctuation, the use of renewable energy may offer, along with environmental benefits, greater stabilization of electricity costs. The pricing volatility of fossil fuels, along with the difficulty of forecasting fossil fuel prices, puts energy customers and providers at risk from fluctuating energy rates. As an alternative, this paper explores the potential for renewable energy to serve as a financial "hedge," reducing exposure to

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[16] Susan Tierney, et al., New York Independent System Operator, *Fuel Diversity in the New York Electricity Market* at 35 (October 2008), *available at* http://www.nyiso.com/public/webdocs/media_room/publications_presentations/White_Papers/White_Papers/fuel_diversity_11202008.pdf. Attached hereto as Exhibit EAS-6.

[17] Mark Bolinger and Joachim Seel, Lawrence Berkeley National Laboratory, *Utilitiy Scale Solar 2014:An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* at 35 (September 2015). Attached hereto as Exhibit EAS-7.

fuel price risk. Renewable energy generation brings with it the price stability benefits of free-fuel generation from emerging technologies such as solar, wind, small hydro, and geothermal sources. Renewable energy costs tend to be stable or decreasing over time, compared to rising or fluctuating costs for fossil fuel. [18]

Q. Have electric utilities acknowledged the risk reducing benefits of generation diversity?

A. Yes. A 2014 study of the benefits of power supply diversity commissioned by the Edison Electric Institute together with the Nuclear Energy Institute and the U.S. Chamber of Commerce found that utilities experienced a reduced exposure to fuel price volatility when they relied on a more diverse mix of fuels and technologies.[19] This study referred to generation diversity as "the most cost-effective tool" for managing risk in electric generation costs and found cost reductions associated with greater resource diversity:

> Engineering and economic analyses consistently show that an integration of different fuels and technologies produces the least-cost power production mix. Power production costs change because the input fuel costs— including for natural gas, oil, coal, and uranium—change over time. The inherent uncertainty around the future prices of these fuels

[18] Dan Lieberman and Siobhan Doherty, Commission for Environmental Cooperation, *Renewable Energy as a Hedge Against Fuel Price Fluctuation: How to Capture the Benefits* at 4, (2008), *available at* http://www.cec.org/islandora/en/item/2360-renewable-energy-hedge-against-fuel-price-fluctuation-en.pdf. Attached hereto as Exhibit EAS-8.
[19] Makovich, Exhibit EAS-2.

> translates into uncertainty regarding the cost to produce electricity, known as production cost risk. A diversified portfolio is the most cost-effective tool available to manage the inherent production cost risk involved in transforming primary energy fuels into electricity.
>
> The best available tool for managing uncertainty associated with any single fuel or technology is to maintain a diverse power supply portfolio.[20]

In addition, the Electric Power Research Institute (EPRI)—which includes in its membership the vast majority of U.S. electric utilities—released a 2015 analysis of generation and fuel diversity describing how a lack of diversity can lead to exposure to fuel price volatility, and discussing the importance of generation diversity in resource planning.

> If companies and regions have a strong reliance on only one or two fuels for power generation, this situation can lead to large swings in electric prices if the dominant fuel exhibits large price volatility… Wind and solar resources typically have no fuel cost, which automatically implies low fuel price volatility. Typically, natural gas not only costs more to generate a MWh of output than doing so with wind or solar, but natural gas prices have been highly volatile throughout recent history as a fuel for power generation
>
> Currently, capacity additions in the U.S. electric industry are dominated by natural gas-fired generators and renewable power plants. The amount of

[20] *Id*. at 5-6

> natural gas based power plants being developed, and the dominance of new natural gas-fired capacity, has raised concerns among company executives, power planners and regulators. These concerns center on the extent to which the industry is "putting too many of its eggs into one basket." In more rigorous terms, some industry participants are questioning whether the amount of natural gas based power generation being added to the current generation fleet is leading to a lack of generation diversity.[21]

Q: Is generation diversity a standard measure taken to reduce the risk of fuel price diversity?

A. Yes, based on my own experience in this field and the information that I reviewed and described above, generation diversity is a standard measure taken to reduce the risk of fuel price diversity.

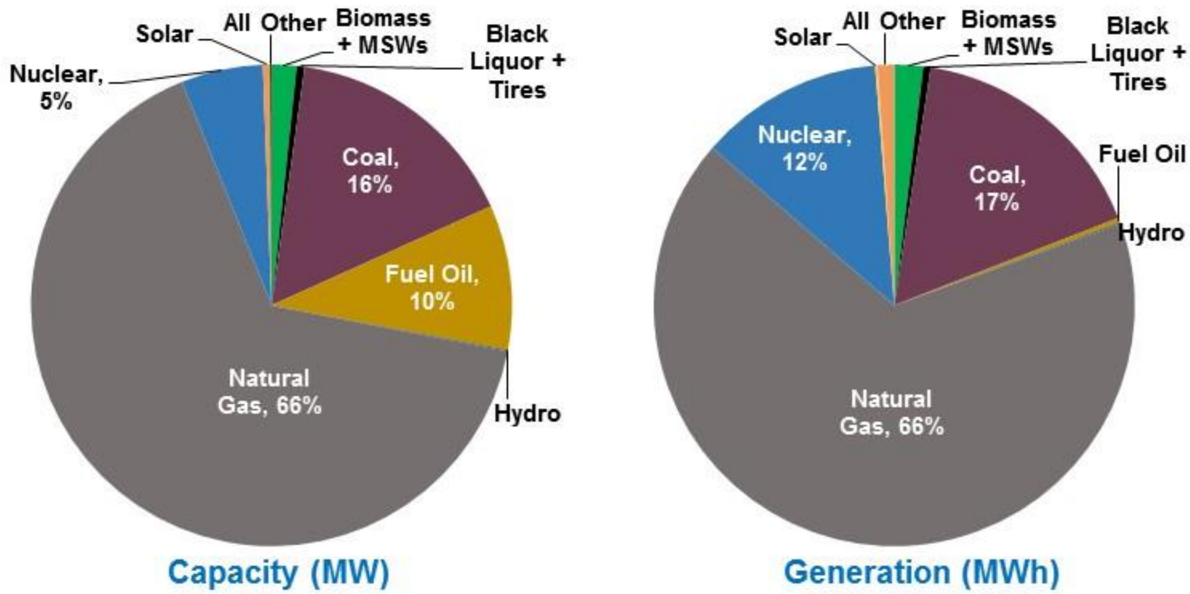
V. FLORIDA'S HEAVY RELIANCE ON GAS EXPOSES ITS RATEPAYERS TO FUEL PRICE VOLATILITY

Q. What is the current composition of generation resources in Florida?

A. In 2016, Florida's electric generation included 66 percent natural gas, 17 percent coal, 12 percent nuclear, and just 4 percent of other resources.

[21] Electric Power Research Institute, *Thinking about Generation Diversity—Part 2: Electric Power Plant Asset Portfolio Valuation and Risk*, at 2-3, 5 (March 2015). Attached hereto as Exhibit EAS-9.

Figure 2. Florida's 2016 Electric Capacity and Generation Mix[22]



Q. How does Florida's reliance on natural gas expose ratepayers to fuel price volatility?

A. In 2016, 66 percent of Florida's electric generation came from the state's natural gas generators. This means that two-thirds of Florida's generation is vulnerable to natural gas price volatility.

Q. How much of each of the IOUs' electricity is generated from natural gas?

A. According to EIA data, in 2016:[23]

- **DEF:** 73 percent of total generation from natural gas
- **FPL:** 74 percent of total generation from natural gas

[22] Charts based on EIA Data.
[23] Data reproduced here from EIA 2016 Form 923.

- **TECO:** 56 percent of total generation from natural gas

Q. How does Florida's reliance on natural gas generation capacity compare to that of other U.S. states?

A. As reflected in Figure 2 below, only four states have a higher share of their capacity invested in natural gas generation: Delaware, Louisiana, Mississippi, and Rhode Island. Of these, Delaware and Rhode Island are each part of highly integrated ISO regions with far lower total concentrations of natural gas generation; these small states get their generation, and corresponding generation diversity, from the larger multi-state region around them. Delaware and Rhode Island can access the larger multi-state region's diverse composition of generation and thus are not captive to natural gas price volatility. Accordingly, Florida is an outlier when compared to other states' reliance on gas for electricity generation.

Q. How does Florida's reliance on gas in terms of actual generation compare to that of other U.S. states?

A. By percent of generation, Florida's reliance on natural gas is also 66 percent, again higher than all but four states: Delaware, Mississippi, Nevada, and Rhode Island (see Figure 5 below).

Figure 3. Reliance on Natural Gas Generating Capacity (% of MW) By State[24]

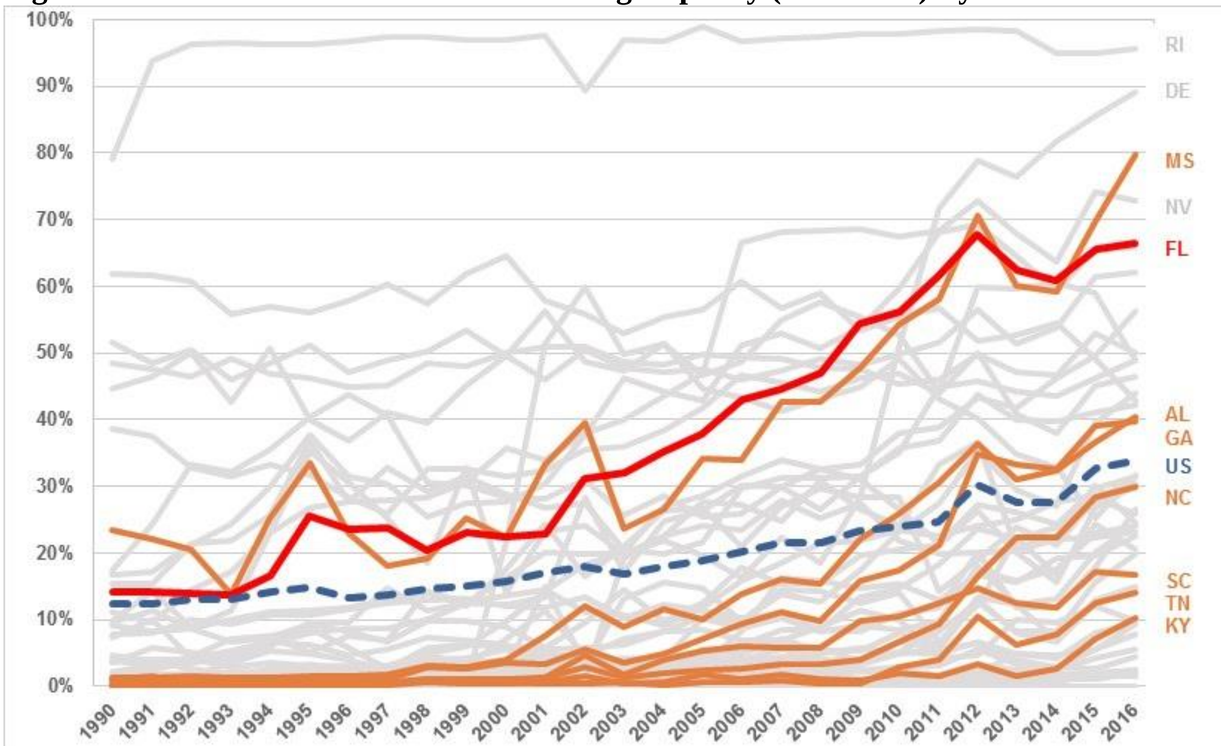
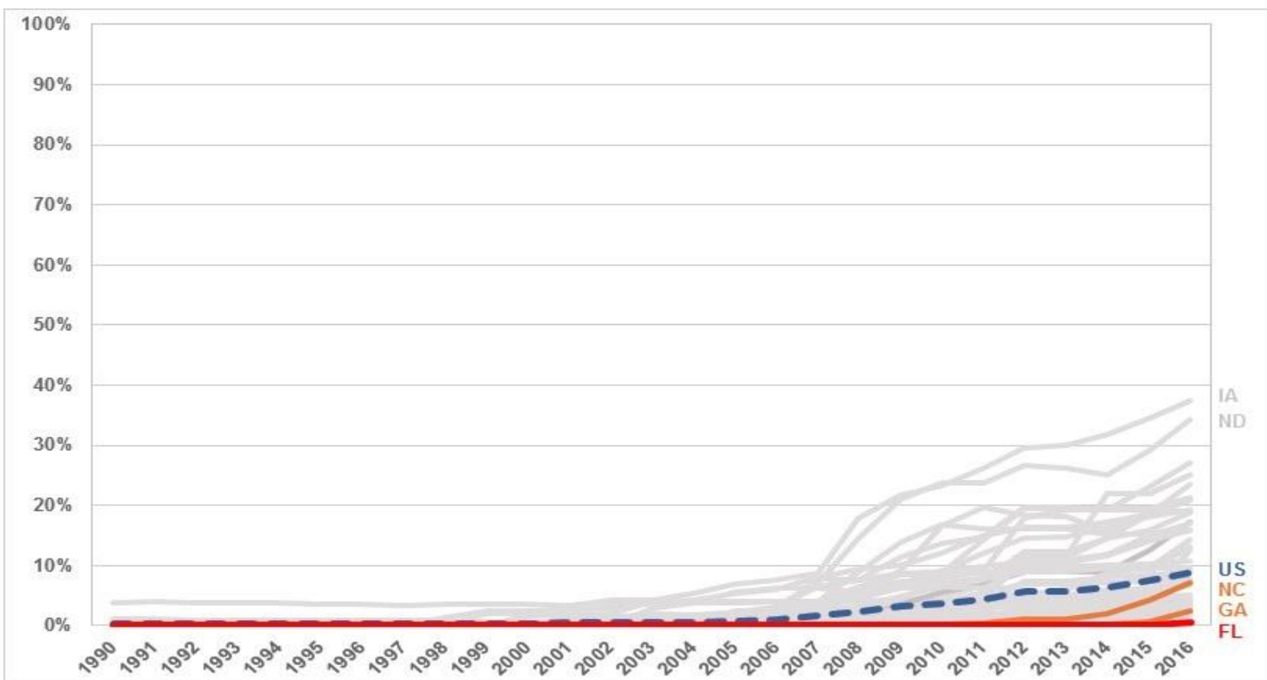


Figure 4. Reliance on Renewable Generating Capacity (% of Mw) By State[25]



[24] Based on EIA Forms 860 and 923 data.
[25] Based on EIA Forms 860 and 923 data.

Figure 5. Reliance on Natural Gas Generation (% of Mwh) By State[26]

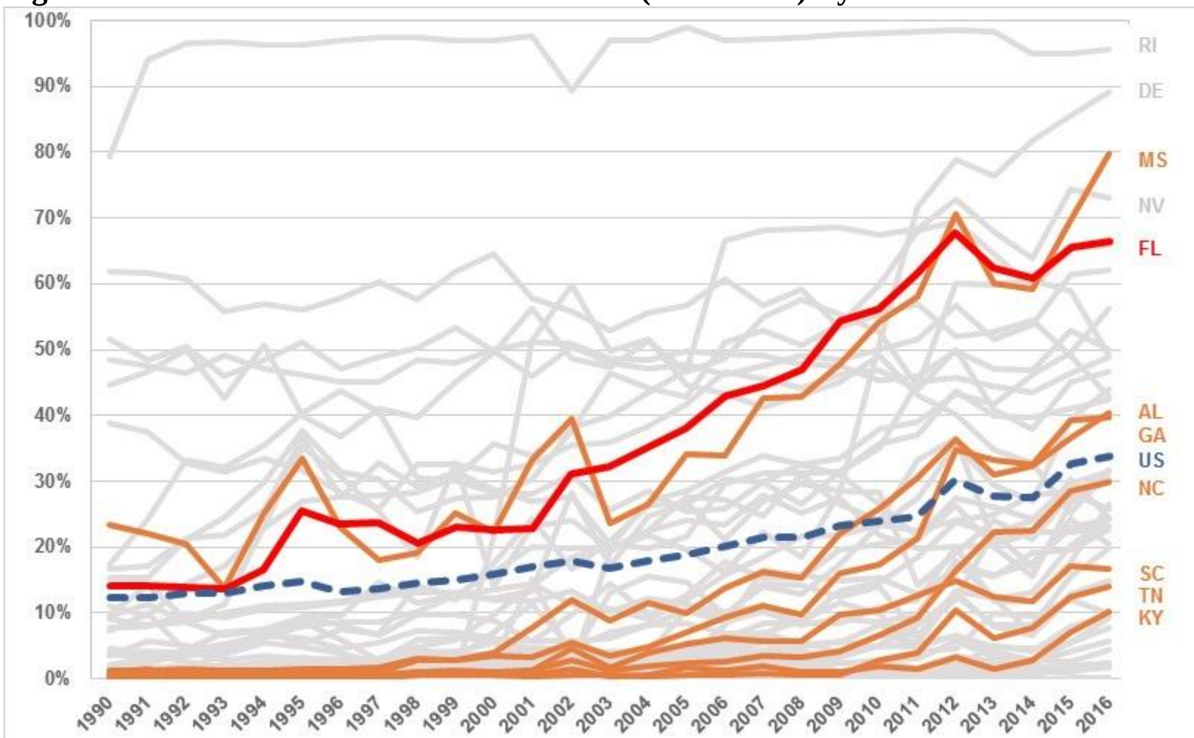
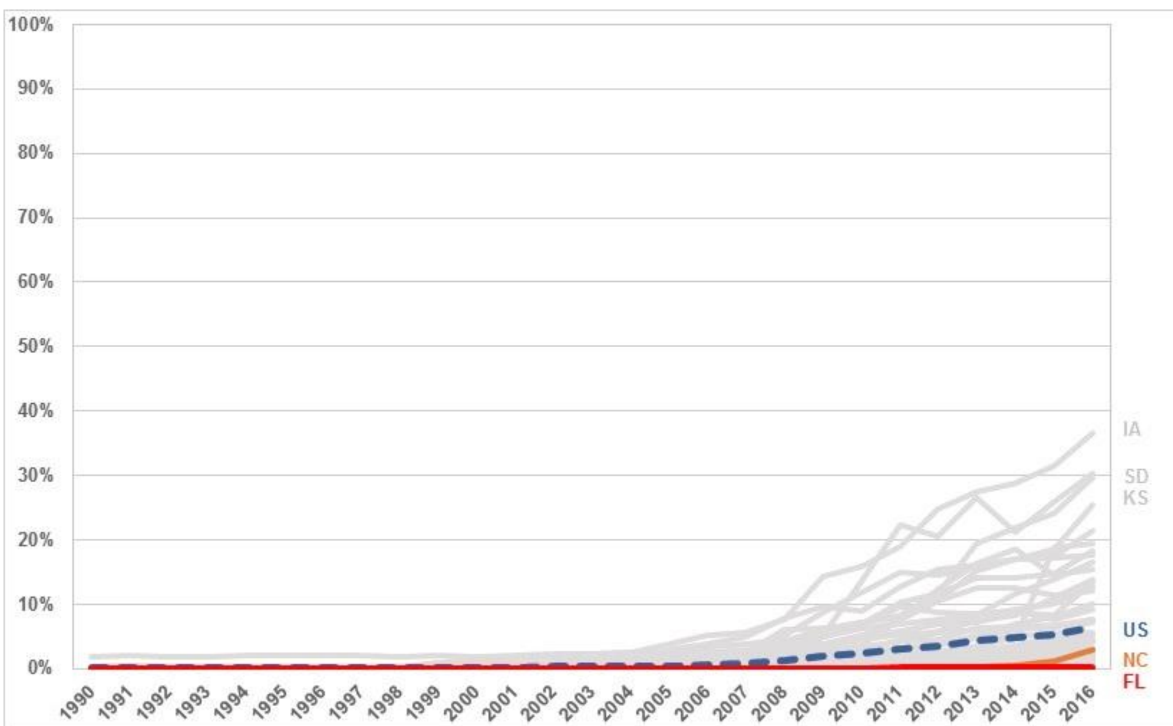


Figure 6. Reliance on Renewable Gene ration (% of Mwh) By State[27]



[26] Based on EIA Forms 860 and 923 data.

[27] Based on EIA Forms 860 and 923 data.

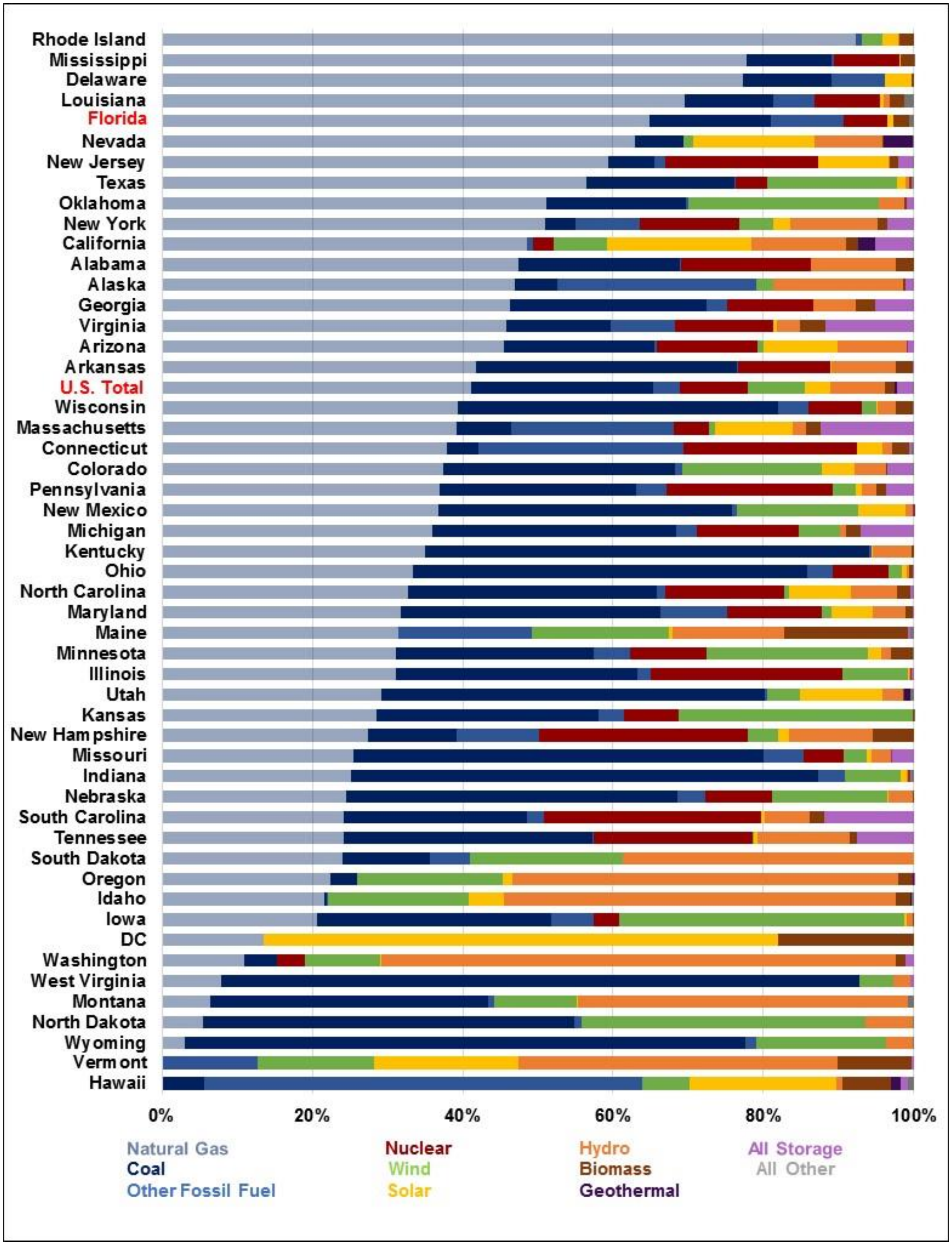
Q. How has Florida's reliance on natural gas for electric generation changed over time?

A. The share of Florida's electricity generated with natural gas has more than quintupled since 1990 from 8,613 MW to 45,487 MW of capacity. Since 2002, when the Commission first authorized the utilities to financially hedge natural gas prices, the state's reliance on natural gas has more than doubled.

Q. Overall, how does Florida's generation and fuel diversity compare to other states?

A. As shown in Figure 7 (which includes both distributed and utility-scale renewables) Florida's dependence on natural gas stands out both in comparison to the U.S. total and in comparison to most of its neighbors in the Southeast region.

Figure 7. Net Generating Capacity by State Including Distributed Generation (Summer 2017)[28]



Q. How has Florida's electricity mix changed in the past fifteen years?

A. Since 2002, Florida's dependence on natural gas has more than doubled conversely its reliance on zero-fuel renewables, and solar in particular, has lagged far behind the state's potential.

VI. FLORIDA'S IOUS HAVE ONLY MADE LIMITED INVESTMENTS IN RENEWABLES AND ENERGY EFFICIENCY.

Q. What is Florida's potential for renewable generation?[29]

A. The National Renewable Energy Laboratory's (NREL) 2012 review of U.S. renewable energy potential found that Florida has nearly 2.96 million MWs of potential renewable generation capacity. Solar represents 2.90 million MWs of capacity with the remainder from geothermal and off-shore wind. The solar potential identified by NREL for Florida includes 49,000 MW for distributed rooftops, 40,000 MW for urban utility-scale, and 2.81 million MW for rural solar farms.[30] My testimony focuses on Florida's solar potential because those resources far exceed the state's potential for other forms of renewable energy.

Q. How does Florida's investment in renewable resources compare to that of other states?

A. Florida's renewable generating capacity as a share of its total capacity is the fifth lowest among all states (see

[29] Throughout this testimony, unless indicated otherwise, the term renewables refers to resources like solar that require no fuel input.
[30] Anthony Lopez, et al., NREL, *U.S. Renewable Energy Technical Potentials: GIS-Based Analysis*, (July 2012). Attached hereto as Exhibit EAS-10.

Figure *4* above). Florida currently has 502 MW of total solar photovoltaic generation, no wind generation, and 54 MW of hydroelectric generation. Florida's total share of generation from renewables is also very small compared to other states (see Figure 6 above). Only five states had a smaller share of generation from renewables than Florida in 2016.

Q. Is Florida's potential for renewable generation being fully utilized?

A. No. Florida has developed only 502 MW of its potential 2.90 million MWs of solar generation. This means that Florida is using less than 2/100ths of 1 percent of its solar potential.

Q. What is Florida's potential for energy efficiency?

A. Energy efficiency refers to the set of measures and policies that allow electric consumers to use less energy while achieving a similar level or quality of services. Energy efficiency measures are typically one of the least cost resources that electric utilities can employ to reduce customer costs. In Florida, more energy efficiency means lower electric sales, displacing generation and fuel purchases for natural gas, and lower monthly bills for ratepayers. EPRI's 2014 study of U.S. energy efficiency potential found 19 percent of Florida's retail sales could be saved through efficiency measures.[31]

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[31] Electric Power Research Institute, *U.S. Energy Efficiency Potential Through 2035*, tbl. B-2 (2014), *available at* https://www.epri.com/#/pages/product/000000000001025477/. Attached hereto as Exhibit EAS-11.

Q. How does Florida's investment in energy efficiency compare to that of other states?

A. The American Council for an Energy-Efficient Economy's (ACEEE) 2016 *State Energy Efficiency Scorecard* ranked Florida 25th among all states. Florida's 2015 annual incremental efficiency savings amounted to 0.1 percent of the state's retail electric sales. Sixteen states saved more than 1 percent (or ten times the amount saved in Florida) of electric sales through annual incremental increases to efficiency in 2015; three states saved more than 2 percent.[32]

Q. Is Florida fully utilizing its renewable and energy efficiency resources?

A. No, based on my own experience in this field and the information that I reviewed and described above, Florida's investment in renewables and energy efficiency has lagged far behind its buildup of natural gas resources.

VII. AN ALTERNATIVE, LOWER-COST SOLUTION: INVESTING IN RENEWABLES AND ENERGY EFFICIENCY TO REDUCE GAS USE AND THE ASSOCIATED RISK OF FUEL PRICE VOLATILITY

Q. How will investing in renewables and energy efficiency reduce customers' exposure to volatile fuel prices?

A. Investing in renewables and energy efficiency would enhance Florida's generation diversity and, as a consequence, reduce the electric consumers' vulnerability to fuel price volatility and upward pressure on rates. Much of an electric consumer's utility

[32] Weston Berg, et al., American Council for an Energy-Efficient Economy, *The 2016 State Energy Efficiency Scorecard*, (September 2016). Attached hereto as Exhibit EAS-12.

bill goes towards paying for the generation that makes their electricity. The costs to consumers depend on the particular resources chosen to supply the generation and how much each resource costs. Typically energy efficiency measures and resources like solar generation that have very low per kilowatt-hour costs are "must run": these resources are the first chosen to run and/or run automatically without being selected by the electric grid operator. For this reason, efficiency and renewables push out or "displace" other generating resources that are more costly to run on a per kilowatt-hour basis. More efficiency and renewable generation means less dispatch of natural gas (and other thermal generation), and therefore cost savings from avoided fuel use.

Q. How much of the consumers' money have Florida's electric utilities lost as a result of past hedging of natural gas prices?

A. From 2007-2016 DEF, FPL, and TECO registered cumulative hedging losses of $6.9 billion (summed in nominal dollars).[33] This means that had DEF, FPL, and TECO not engaged in hedging on the price of natural gas, their customers would have paid $6.9 billion less on their electric bills from 2007 through 2016.

Q. Is it possible to estimate the impacts that would have occurred if Florida's utilities had spent ratepayers' money on renewables and efficiency instead of financial hedges?

A. Yes. The impacts of alternative investments of the $6.9 billion in lost hedging payments can be estimated in several ways, including detailed, formal modeling.

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[33] Data derived from the IOUs responses to Sierra Club's First Set of Interrogatories, Interrogatory No. 4. Losses over that period were registered as follows: DEF: $2.0 billion; FPL: $4.2 billion; TECO: $0.4 billion.

Here, I performed a simple illustrative analysis to give a preliminary estimate of possible impacts.

Q. What did your illustrative analysis of alternative investment of Florida ratepayers' $6.9 billion reveal?

A. To summarize, I found that if ratepayers' money had been spent on renewables and energy efficiency instead of financial hedges for the last ten years, it would have been possible to reduce Florida's expenditures on natural gas for electric generation by 8 percent while passing $6.6 billion in savings along to consumers in their electric bills. On average over the past 10 years, a $1 investment in renewables and efficiency would have returned $0.95 in fuel savings. (For comparison, each $1 investment in fuel-price hedges over this period returned $0 to consumers.)

My analysis looked only at savings from fuel not purchased. An 8 percent reduction in natural gas generation would also secure additional savings from avoided power plant operation and maintenance, and could potentially make capital expenditures on repairs or replacement generation unnecessary. These additional savings could further increase the return on each dollar of renewable and energy efficiency investment. A detailed explanation of my illustrative analysis is presented below.

Q. How did you perform your illustrative analysis?

A. I performed a "what if" exercise as a simple, illustrative spreadsheet analysis to estimate the impacts of investing the amount of funds customers lost due to the IOUs' hedging from 2007 through 2016 in renewables and efficiency. In this "what if" analysis Florida's ratepayers did not pay for any fuel price hedging:

- I chose a ten-year period for the analysis to provide a simple example that would be consistent for all utilities. The last ten years for which I had natural gas price data were 2007 through 2016.
- I assumed that Florida's $6.9 billion in hedging losses were spent one-half on solar energy and one-half on energy efficiency. I chose solar energy as the source of all renewable energy investment in this illustration because of Florida's tremendous untapped solar potential. Likewise, I chose energy efficiency as a component because Florida has ample opportunity to achieve greater energy efficiency improvements. Further—for simplicity—I assumed that this spending was structured in the manner of ten-year purchase-power agreements. As a result, $350 million was spent each year from 2007 through 2016 on purchasing solar generation and $350 million was spent each year on energy efficiency.
- At $110 per megawatt-hour (MWh) (chosen as a levelized cost of solar in 2007, the year in which the purchase-power agreement would be contracted),[34] $350 million buys 3.2 million MWh of solar generation each year. Annual generation of 3.2 million MWh of solar is approximately equal to 1,500 megawatts of capacity at a 25 percent capacity factor.[35]

[34] Today's solar prices are lower, and expected future solar prices are lower still. For example, in 2015 the Jacksonville Electric Authority received quotes as low as $59/MWh in response to a request for proposals issued for solar PPAs. Jacksonville Electric Authority, *2015 Solar RFP – Phase 2 Summary* at 1, June 10, 2015, *available at* https://www.jea.com/About/Procurement/Bid_Results/Solar_2015_-_June_11,_2015.aspx. Attached hereto as Exhibit EAS-13. Since then, total solar installation costs have dropped over 20 percent while national solar module prices have fallen over 30 percent. U.S. Department of Energy, *Q4 2016/Q1 2017 Solar Industry Update* at 21, 48, April 25, 2017, *available at* http://www.nrel.gov/docs/fy17osti/68425.pdf. Attached hereto as Exhibit EAS-14.

[35] The 25 percent capacity factor chosen for this illustration is conservative; a higher capacity factor would yield even greater savings.

- At $35 per MWh,[36] $350 million buys 10.0 million MWh of energy efficiency savings each year (this could also be thought of as a $3.5 billion incremental energy efficiency investment in 2007 with no additional investment in 2008 to 2016).
- Together these investments displace 13.1 million MWh of natural gas generation each year—that's 6 percent of Florida's 2016 electric sales. Put another way, using the assumption that natural gas generation is "on the margin" in Florida—and, therefore, the first type of generation not to run in the event that new, additional generation is available or sales are reduced: 13.1 million MWh of renewables and efficiency savings make 13.1 million MWh of natural gas generation unnecessary.
- This displaced natural gas generation relieves Florida's electric customers of the need to purchase 101 to 107 trillion cubic feet of natural gas each year (the amount depends on the average efficiency of the plants, which changes over time) and reduces their vulnerability to natural gas price volatility. In 2016, 101 trillion cubic feet of natural gas was 9 percent of Florida's total natural gas purchases.

[36] This value is ACEEE's levelized cost of saved energy for energy efficiency from 2007.

- The savings to electric customers is the number of cubic feet avoided multiplied by the price of natural gas to Florida's electric generators (which also changes over time).[37] Overall, applying my analysis described above, from 2007 to 2016, spending $6.9 billion on renewables and efficiency saves $6.6 billion on natural gas purchases.
- Arguably, still more money could have been saved in avoided operations and maintenance and avoided capital expenses on major improvements to or replacement of older plants; these additional savings are not included in the estimates presented here.

Overall, investing the $6.9 billion hedging losses instead in renewables and efficiency over the period 2007 to 2016 would have reduced the state's dependence on natural gas for electricity generation by 9 percent and provided consumers with $6.6 billion in savings.

In this "what if" analysis, each investment in renewables and efficiency during the 2007 to 2016 period has an out-of-pocket cost of about 5 percent (the other 95 percent is returned to consumers in fuel price savings). For a cost of 5 cents on the dollar, vulnerability to natural gas price volatility is reduced.

In contrast, every $1 spent on financial hedging losses returned $0 to the ratepayers.

[37] Natural gas prices for this analysis were derived from the reference case for EIA's Annual Energy Outlook for 2017.

Q. Are there any alternative, lower-cost solutions to reduce gas use and the associated risk of fuel price volatility other than financial hedging?

A. Yes, based on the analysis outlined above, alternative, lower-cost solutions to reduce natural gas use and the associated risk of fuel price volatility are available.

VIII. CONCLUSION

Q. What are the key findings of your testimony?

A. Based on the information that I reviewed in this docket, the Florida specific analysis that I present below, my relevant experience and knowledge, and review of professional literature on fuel price volatility and risk reducing measures, my findings are as follows:

- Solar and energy efficiency improve generation diversity and thereby help reduce fuel price volatility and save customers money;
- The IOUs have dramatically increased their investments in natural gas generation while pursuing very low levels of investment in renewables and energy efficiency;
- Greater investments in solar and energy efficiency, over the past ten years, would have yielded extensive customer savings.
- The IOUs' failure to diversify their resource mix now renders their customers more exposed to natural gas price volatility than customers in most other states; and

- To reduce exposure to natural gas price volatility, the IOUs should instead evaluate and pursue generation diversity, especially through added solar and energy efficiency.

Q. What are your recommendations do you offer in this docket?

A. Based on these findings, I recommend that the Commission find that continuing the exclusive use of financial hedges to control customer exposure to natural gas price volatility is not in the consumers' best interest. The Commission should not reauthorize the use of financial hedges until it is presented with a detailed assessment of alternative ways to limit the risk from fuel price volatility. Solar generation provides electricity without any fuel costs and efficiency reduces the amount of natural gas required to meet demand. As such these resources reduce ratepayers' vulnerability to fluctuations in natural gas prices. At the same time, solar and efficiency provide lasting benefits to customers.

Q. Does this conclude your testimony?

A. Yes it does.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing was served electronically on this 10th day of August, 2017 on:

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IHS™ **Energy**

The Value of US Power Supply Diversity

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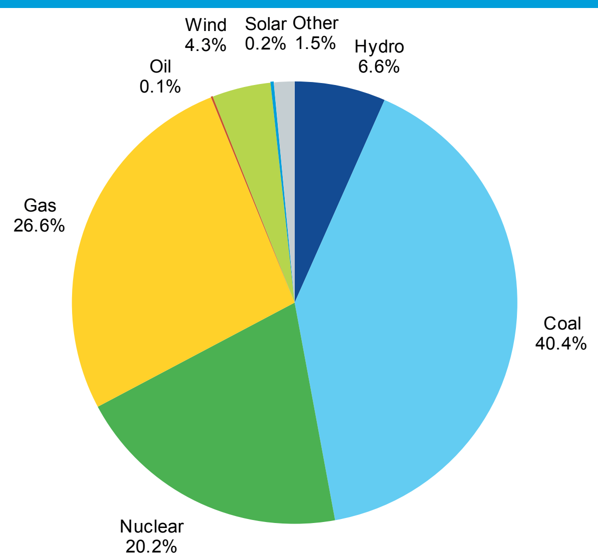
Executive summary

Engineering and economic analyses consistently show that an integration of different fuels and technologies produces the least-cost power production mix. Power production costs change because the input fuel costs—including for natural gas, oil, coal, and uranium—change over time. The inherent uncertainty around the future prices of these fuels translates into uncertainty regarding the cost to produce electricity, known as production cost risk. A diversified portfolio is the most cost-effective tool available to manage the inherent production cost risk involved in transforming primary energy fuels into electricity. In addition, a diverse power generation technology mix is essential to cost-effectively integrate intermittent renewable power resources into the power supply mix.

The current diversified portfolio of US power supply lowers the cost of generating electricity by more than $93 billion per year, and halves the potential variability of monthly power bills compared to a less diverse supply. Employing the diverse mix of fuels and technologies available today produces lower and less volatile power prices compared to a less diverse case with no meaningful contributions from coal and nuclear power and a smaller contribution from hydroelectric power (see Figure ES-1). In this less diverse scenario, called the *reduced diversity case,* wind and solar power make up one-third of installed capacity (up from about 7% in the base case) and 22.5% of generation; hydroelectric power capacity decreases from about 6.6% to 5.3% and represents 3.8% of generation; and natural gas–fired power plants account for the remaining 61.7% of installed capacity and 73.7% of generation.

FIGURE ES-1

US generation mix, 2013



Source: IHS Energy

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Power supply in the reduced diversity case increases average wholesale power prices by about 75% and retail power prices by 25%. Energy production costs are a larger percentage of industrial power prices, and many industrial consumers buy power in the wholesale power market. Thus a loss of power supply diversity will disproportionally affect the industrial sector. These higher electricity prices impact the broader US economy by forcing economic adjustments in production and consumption. If the US power sector moved from its current diverse generation mix to the less diverse generating mix, power price impacts would reduce US GDP by nearly $200 billion, lead to roughly one million fewer jobs, and reduce the typical household's annual disposable income by around $2,100. These negative economic impacts are similar to an economic downturn. Additional potential negative impacts arise from reducing power supply diversity by accelerating the retirement of existing power plants before it is economic to do so. For example, a transition to the reduced diversity case within one decade would divert around $730 billion of capital from more productive applications in the economy. The size of the economic impact from accelerating power plant turnover and reducing supply diversity depends on the deviation from the pace of change dictated by the underlying economics.

Maintaining and preserving a diverse US power supply mix is important to consumers for two reasons:

- Consumers reveal a strong preference for not paying more than they have to for reliable electricity.
- Consumers reveal preferences for some degree of predictability and stability in their monthly power bills.

The economic benefits of diverse power supply illustrate that the conventional wisdom of not putting all your eggs in one basket applies to power production in much the same way as it does to investing. This is the *portfolio effect*. In addition, diversity enables the flexibility to respond to dynamic fuel prices by substituting lower-cost resources for more expensive resources in the short run by adjusting the utilization of different types of generating capacity. This ability to move eggs from one basket to another to generate fuel cost savings is the *substitution effect*. Looking ahead, the portfolio and substitution effects remain critically important to managing fuel price risks because of the relative fuel price dynamics between coal and natural gas.

The shale gas revolution and restrictions on coal are driving an increased reliance on natural gas for power generation and provide strong economic benefits. However, this past winter demonstrated the danger of relying too heavily on any one fuel and that all fuels are subject to seasonal price fluctuations, price spikes, and deliverability and infrastructure constraints. The natural gas price spikes and deliverability challenges during the past winter were a jolt for a number of power systems that rely significantly on natural gas in the generation supply. These recent events demonstrated that natural gas deliverability remains a risk and natural gas prices continue to be hard to predict, prone to multiyear cycles, strongly seasonal, and capable of significant spikes. The root causes of these price dynamics are not going away anytime soon. The best available tool for managing uncertainty associated with any single fuel or technology is to maintain a diverse power supply portfolio.

Maintaining power supply diversity is widely supported—the idea of an all-of-the-above approach to the energy future is supported on both sides of the aisle in Congress and at both ends of Pennsylvania Avenue. Four decades of experience demonstrate the conclusion that government should not pick fuel or technology winners, but rather should create a level playing field to encourage the economic decisions that move the power sector toward the most cost-effective generation mix.

Maintaining a diverse power supply currently is threatened by three emerging trends:

- **Awareness.** The value of fuel diversity is often taken for granted because United States consumers inherited a diverse generation mix based on decisions from decades ago.

- **Energy policy misalignment.** Legislation and regulatory actions increasingly dictate or prohibit fuel and technology choices. The resulting power supply is increasingly at odds with the underlying engineering/economic principles of a cost-effective power supply mix.

- **Power market governance gridlock.** Market flaws produce wholesale power prices that are chronically too low to produce adequate cash flows to support and maintain investments in a cost-effective power generation mix. This "missing money" problem is not being addressed in a timely and effective way through the stakeholder governance processes found in most power markets. As a result, the loss of power supply diversity is accelerating because too many power plants are retiring before it is economic to do so. Consequently, they will be replaced with more costly sources of supply.

US power consumers are fortunate to have inherited a diverse power supply based on fuel and technology decisions made over past decades. Unfortunately, the current benefits of US power supply diversity are often taken for granted. This undervaluation of power supply diversity means there is no counterweight to current pressures moving the United States toward a future generation mix without any meaningful contribution from nuclear, coal, or oil and a diminished contribution from hydroelectric generation.[1]

The United States needs to consider the consequences of a reduced diversity case involving no meaningful contribution from nuclear, coal-fired, or oil-fueled power plants, and significantly less hydroelectric power. A reduced diversity case presents a plausible future scenario in which the power supply mix has intermittent renewable power generation capacity of 5.5% solar, 27.5% wind, and 5.3% hydro and the remaining 61.7% of capacity is natural gas–fired power plants. Comparing the performance of current US power systems to this possible reduced diversity case provides insights into the current nature and value of diversity in the US generation mix.

IHS Energy assessed the current value of fuel diversity by using data on the US power sector for the three most recent years with sufficient available data: 2010 through 2012. IHS Energy employed its proprietary Power System Razor (Razor) Model to create a base case by closely approximating the actual interactions between power demand and supply in US power systems. Following this base case, the Razor Model was employed to simulate the reduced diversity case over the same time period. The differences between the base case and the reduced diversity case provide an estimate of the impact of the current US power supply fuel and technology diversity on the level and variance of power prices in the United States. These power sector outcomes were fed through to the IHS US macroeconomic model to quantify the broader economic impacts of the resulting higher and more varied power prices along with the shifts in capital deployment associated with premature retirements that accelerate the move to the reduced diversity case.

The difference between the base case and the reduced diversity case is a conservative estimate of the value of fuel diversity. The portfolio and substitution values would be greater over a longer analysis time frame because uncertainty and variation in costs typically increase over a longer time horizon. In addition, the estimate is conservative because it excludes indirect feedback effects from a higher risk premium in the reduced diversity power supplier cost of capital. This feedback is not present because the analysis alters only the generation capacity mix and holds all else constant. This indirect cost feedback would increase capital costs in this capital-intensive industry and magnify the economic impact of current trends to replace power plants before it is economic to do so by moving shifting capital away from applications with better risk-adjusted returns.

The United States is at a critical juncture because in the next decade the need for power supply to meet increased customer demands, replace retiring power plants, and satisfy policy targets will require fuel and

1. Oil-fired power plants account for about 4% of US capacity and 0.2% of US generation but can play a critical role in providing additional electricity when the system is under stress.

technology decisions for at least 150 gigawatts (GW)—about 15% of the installed generating capacity in the United States. However, current trends in energy policy could push that power plant turnover percentage to as much as one-third of installed capacity by 2030. The implication is clear: power supply decisions made in the next 10–15 years will significantly shape the US generation mix for decades to come.

The results of this study indicate seven key factors that will shape US power supply diversity in the years to come:

- **Energy policy development.** US policy heavily influences the US power supply mix. Implementing an all-of-the-above energy policy requires properly internalizing the value of fuel diversity.
- **Market structure.** Market flaws distort wholesale power prices downward and result in uneconomic retirement and replacement of existing cost-effective generation resources. This issue and any market structure changes to address it will significantly shape future power plant development.
- **Energy policy discourse.** Preserving the value of fuel diversity depends on public awareness and understanding. The extent and nature of public education regarding the value of power supply diversity may strongly influence public opinion.
- **Planning alignment.** Alignment of fuel and technology choices for power generation with engineering and economic principles is critical to efficient and reliable supply. There is no single fuel or technology of choice for power generation, and all forms of power production have economic, environmental, and reliability impacts.
- **Risk assessment.** To incorporate system considerations into plant-level decisions, prudent fuel price uncertainties must be used with probabilistic approaches to decision making.
- **Flexibility.** Flexibility and exemptions in rule making and implementation allow for the balancing of costs and benefits in power supply systems and may help preserve highly valuable diversity in systemwide decisions as well as on a small but impactful individual plant scale.
- **Scope.** Including fuel price risk and additional storage and transportation infrastructure costs is crucial when evaluating reduced diversity scenarios in comparison to the cost of maintaining and expanding fuel diversity.

The Value of US Power Supply Diversity

Overview

The power business is customer driven: consumers do not want to pay more than necessary for reliable power supply, and they want some stability and predictability in their monthly power bills. Giving consumers what they want requires employing a diverse mix of fuels and technologies in power production. Employing the diverse mix of fuels and technologies available today produces lower and less volatile power prices compared to a less diverse case with no meaningful contributions from coal and nuclear power and a smaller contribution from hydroelectric power. In this less diverse scenario, called the *reduced diversity case,* wind and solar power make up one-third of installed capacity (up from about 7% in the base case) and 22.5% of generation; hydroelectric power capacity decreases from about 6.6% to 5.3% and represents 3.8% of generation; and natural gas–fired power plants account for the remaining 61.7% of installed capacity and 73.7% of generation.

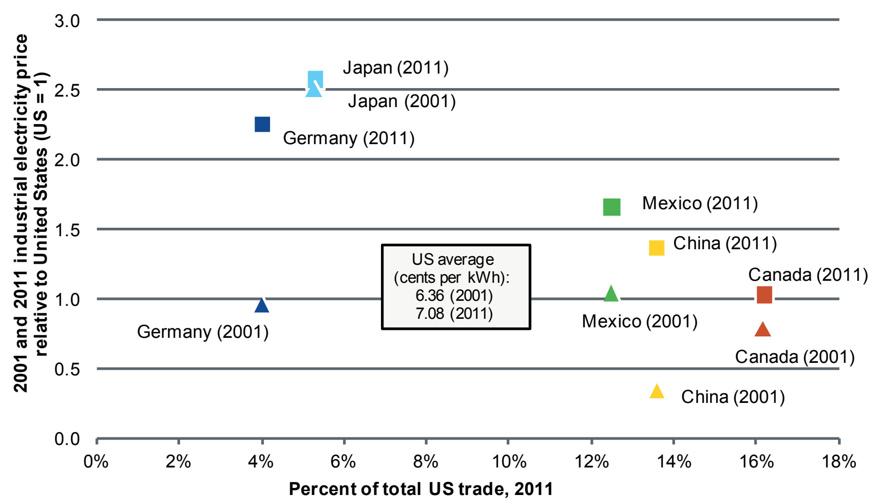
The current diverse US power supply reduces US consumer power bills by over $93 billion per year compared to a reduced diversity case. In addition, the current diversified power generation mix mitigates exposure to the price fluctuations of any single fuel and, by doing so, cuts the potential variability of monthly power bills roughly in half.

Power prices influence overall economic performance. For example, since the recovery of the US economy began in the middle of 2009, manufacturing jobs in the 15 states with the lowest power prices increased by 3.3%, while in the 15 states with the highest power prices these jobs declined by 3.2%. This job impact affected the overall economic recovery. The average annual economic growth in the 15 states with the lowest industrial power prices was 0.6 percentage points higher than in the 15 states with the highest power prices.

Higher and more varied power prices can also impact international trade. In the past decade, the competitive position for US manufacturers improved thanks to lower relative energy costs, including the improving US relative price of electric power (see Figure 1). Although power prices are only one of a number of factors that influence competitive positions in the global economy, there are clear examples, such as Germany, where moving away from a cost-effective power generating mix is resulting in significant economic costs and a looming loss of competitiveness. German power prices increased rapidly over the past decade because Germany closed nuclear power plants before it was economic to do so and added too many wind and solar power resources too quickly into the generation mix. IHS estimates that Germany's net export losses

FIGURE 1

Relative industrial electricity prices for top five US trading partners



Note: Total trade = exports plus imports.
Source: IHS Energy, US Census Bureau, OECD/IEA

directly attributed to the electricity price differential totaled €52 billion for the six-year period from 2008 to 2013.[2]

A less diverse US power supply would make power prices higher and more varied and force a costly adjustment process for US consumers and businesses. The price increase associated with the reduced diversity case produces a serious setback to US economic activity. The value of goods and services would drop by nearly $200 billion, approximately one million fewer jobs would be supported by the US economy, and the typical household's annual disposable income would go down by over $2,100. These economic impacts take a few years to work through the economy as consumers and producers adjust to higher power prices. The eventual economic impacts are greater if current trends force the closure and replacement of power plants before it is economic to do so. Regardless of the replacement technology, it is uneconomic to close a power plant when the costs of continued operation are less than the cost of a required replacement. Premature power plant turnover imposes an additional cost burden by shifting capital away from more productive applications. A closure and replacement of all nuclear and coal-fired generating capacity in the next 10 years would involve roughly $730 billion of investment. An opportunity cost exists in deploying capital to replace productive capital rather than expanding the productive capital base.

The United States currently faces a key challenge in that many stakeholders take the current benefits of power supply diversity for granted because they inherited diversity based on fuel and technology decisions made decades ago. There is no real opposition to the idea of an all-of-the-above energy policy in power supply. Yet, a combination of factors—tightening environmental regulations, depressed wholesale power prices, and unpopular opinions of coal, oil, nuclear, and hydroelectric power plants—are currently moving the United States down a path toward a significant reduction in power supply diversity. A lack of understanding of power supply diversity means momentum will continue to move the United States toward a future generation mix without any meaningful contribution from nuclear, coal, or oil, and a diminishing contribution from hydroelectric generation.

The United States is at a critical juncture because power plant fuel and technology decisions being made today will affect the US power supply mix for decades to come. These decisions need to be grounded in engineering, economic, and risk management principles that underpin a cost-effective electric power sector. Comparing the performance of the current generation mix to results of the reduced diversity case provides key insights into the current nature and value of diversity. An assessment and quantification of the value of power supply diversity will help achieve a more cost-effective evolution of US power supply in the years ahead.

Generation diversity: A cornerstone of cost-effective power supply

If power consumers are to receive the reliable and cost-effective power supply they want, then cost-effective power production requires an alignment of power supply to power demand. Engineering, economic, and risk management assessments consistently show that an integration of fuels and technologies produces the least-cost power production mix. A cost-effective mix involves integrating nondispatchable power supply with dispatchable base-load, cycling, and peaking technologies. This cost-effective generating mix sets the metrics for cost-effective demand-side management too. Integrating cost-effective power demand management capabilities with supply options requires balancing the costs of reducing or shifting power demand with the incremental cost of increasing power supply. Appendix A reviews the principles of engineering, economics, and risk management that lead to the conclusion that cost-effective power supply requires fuel and technological diversity.

2. See the IHS study *A More Competitive Energiewende: Securing Germany's Global Competitiveness in a New Energy World*, March 2014.

The underlying principles of cost-effective power supply produce five key insights:

- There is no single fuel or technology of choice for power generation. Reliably and efficiently supplying consumers with the amounts of electricity they want when they want it requires a diverse generation mix.
- A cost-effective generation mix involves diversity but does not involve maximizing diversity by equalizing generation shares from all available supply options.
- A cost-effective mix of fuel and technologies for any power system is sensitive to the uncertainties surrounding the level and pattern of consumer power demands as well as the cost and performance of alternative power generating technologies and, in particular, the delivered fuel prices.
- A cost-effective generating mix will differ from one power system to the next because of differences in aggregate consumer demand patterns as well as in the cost and performance of available generating options.
- The best type of capacity to add to any generation portfolio depends on what types of capacity are already in the mix.

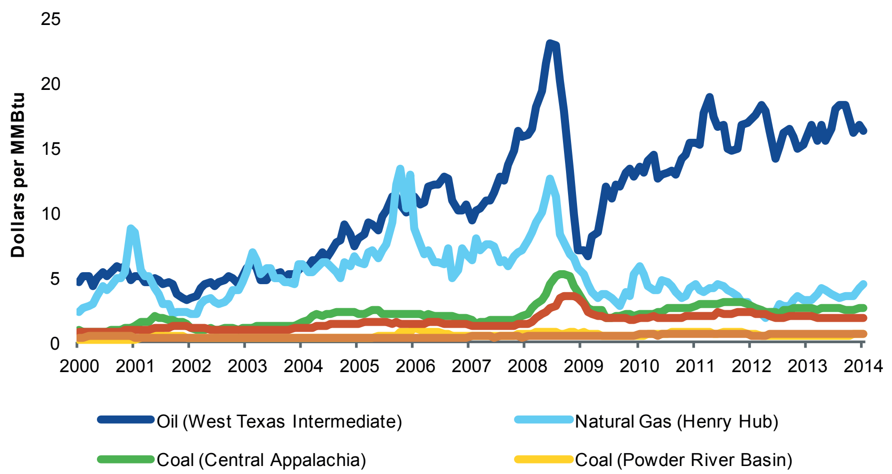
Power production cost fluctuations reflect inherent fuel price uncertainties

Power consumers reveal preferences for some degree of predictability and stability in their monthly power bills. These consumer preferences present a challenge on the power supply side because the costs of transforming primary energy—including natural gas, oil, coal, and uranium—into electric power is inherently risky. Experience shows that the prices of these fuel inputs to the power sector are difficult to anticipate because these prices move in multiyear cycles and fluctuate seasonally (see Figure 2). In addition, this past winter showed that dramatic price spikes occur when natural gas delivery systems are pushed to capacity (see Figure 3).

The recent volatility in the delivered price of natural gas to the US Northeast power systems demonstrates the value of fuel diversity. During this past winter, colder-than-normal weather created greater consumer demand for natural gas and electricity to heat homes and businesses. The combined impact on natural gas demand strained the capability of pipeline systems to deliver natural gas in the desired quantity and pressure. Natural gas prices soared, reflecting the market forces allocating available gas to the highest valued end uses. At some points in time, price allocation was

FIGURE 2

Monthly spot oil, natural gas, and coal prices, 2000–14 year to date



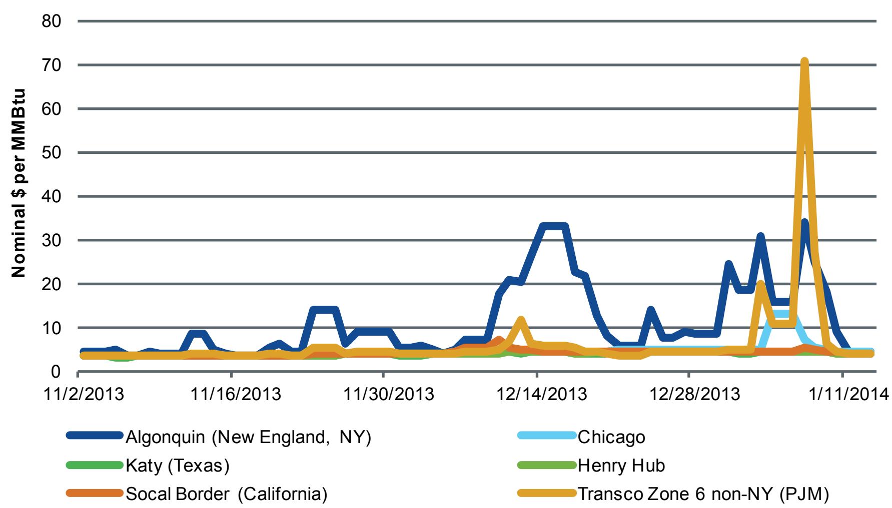
Source: IHS Energy
Data Sources: Energy Information Administration, Platt's and Natural Gas Intelligence, Platts Coal Outlook, SNL Energy Coal © 2014 IHS

not enough and additional natural gas was not available at any price, even to power plants holding firm supply contracts.

As high as the natural gas price spikes reached, and as severe as the natural gas deliverability constraints were, things could have been worse. Although oil-fired power provided only 0.35% of generation in the Northeast in 2012, this slice of power supply diversity provided an important natural gas supply system relief valve. The oil-fired power plants and the dual-fueled oil- and natural gas–fired power plants were able to use liquid fuels to generate 12% of the New England power supply during the seven days starting 22 January 2014 (see Figure 4). This oil-fired generation offset the equivalent of 327,000 megawatt-hours (MWh) of natural gas–fired generation and thus relieved the natural gas delivery system of about 140 million cubic feet per day of natural gas deliveries. This fuel diversity provided the equivalent to a 6% expansion of the daily delivery capability of the existing natural gas pipeline system.

FIGURE 3

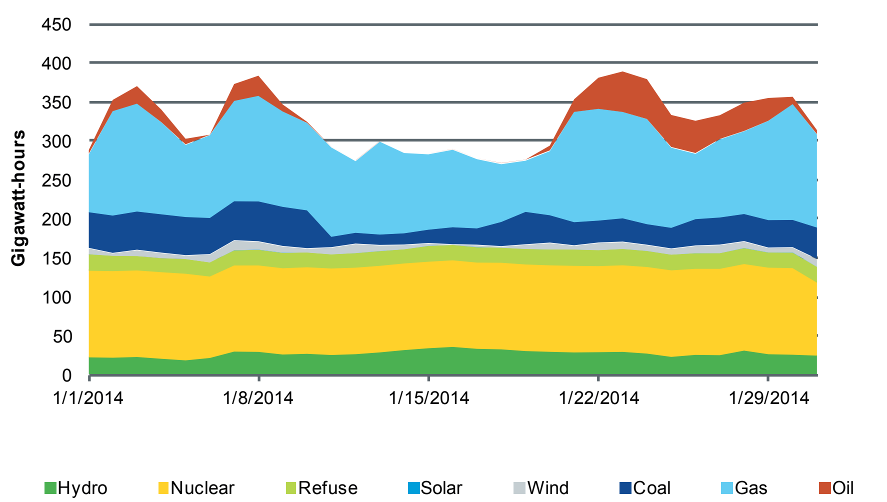
Delivered daily gas prices, November 2013–January 2014



Source: IHS Energy, Ventyx Velocity Suite © 2014 IHS

FIGURE 4

ISO New England generation, January 2014



Source: IHS Energy © 2014 IHS

The lesson from this past winter was that a small amount of oil-fired generation in the supply mix proved to be highly valuable to the Northeast energy sector despite its production costs and emission rates. Many of these oil-fired power plants are old and relatively inefficient at converting liquid fuel to power. However, this relative inefficiency does not impose a great penalty because these power plants need to run very infrequently to provide a safety valve to natural gas deliverability. Similarly, these units have emissions rates well above those achievable with the best available technology, but the absolute amount of emissions and environmental impacts are small because their utilization rates are so low. Although the going forward costs and the environmental impacts are relatively small, the continued operation of these oil-fired power plants is at risk from tightening environmental regulations.

Oil-fired power plants were not the only alternative to natural gas–fired generation this past winter. Coal played a major role. As the *New York Times* reported on 10 March 2014, 89% of American Electric Power Company, Inc.'s 5,573 megawatts (MW) of coal-fired power plants slated for retirement in 2015 owing to tightening environmental regulations were needed to keep the lights on during the cold snap this past winter in PJM.[3]

The critical role fuel diversity played during the recent polar vortex affected power systems that serve over 40 million US electric consumers and almost one-third of power supply. This widespread exposure to natural gas price and deliverability risks is becoming increasingly important because the share of natural gas in the US power mix continues to expand. The natural gas–fired share of power generation increased from 16% to 27% between 2000 and 2013. Twelve years ago, natural gas–fired generating capacity surpassed coal-fired capacity to represent the largest fuel share in the US installed generating mix. Currently, natural gas–fired power plants account for 40% of the US installed capacity mix.

The increasing dependence on natural gas for power generation is not an accident. The innovation of shale gas that began over a decade ago made this fuel more abundant and lowered both its actual and expected price. But the development of shale gas did not change the factors that make natural gas prices cyclical, volatile, and hard to forecast accurately.

Factors driving natural gas price dynamics include

- Recognition and adjustment lags to market conditions
- Over- and under-reactions to market developments
- Linkages to global markets through possible future liquefied natural gas (LNG) trade
- Misalignments and lags between natural gas demand trends, supply expansions, and pipeline investments
- "Black swan" events—infrequent but high-impact events such as the polar vortex

Natural gas price movements in the shale gas era illustrate the impact of recognition and adjustment lags to changing market conditions. Looking back, natural gas industry observers were slow to recognize the full commercialization potential and magnitude of the impact that shale gas would have on US natural gas supply. Although well stimulation technologies date back to the 1940s, today's shale gas technologies essentially began with the innovative efforts of George Mitchell in the Barnett resource base near Fort Worth, Texas, during the 1980s and 1990s. Mitchell Energy continued to experiment and innovate until eventually proving the economic viability of shale gas development. As a result, shale gas production expanded (see Figure 5).

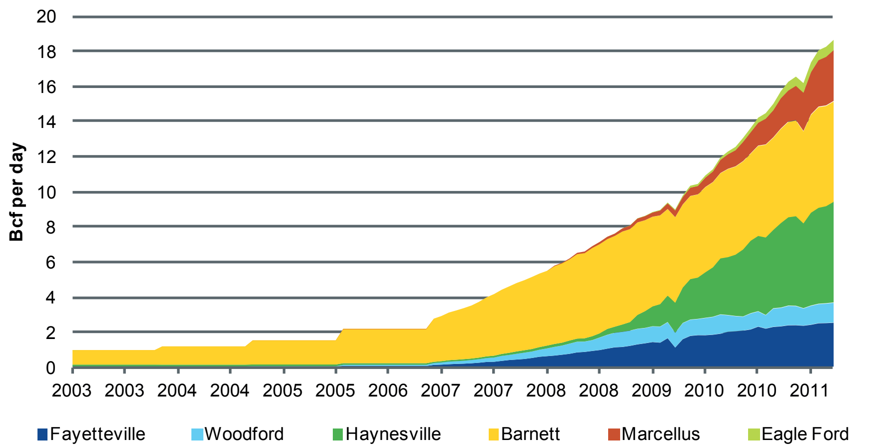
Although shale gas had moved from its innovation phase to its commercialization phase, many in the oil and gas industry did not fully recognize what was happening even as US shale gas output doubled from 2002 to 2007 to reach 8% of US natural gas production. The belief that the United States was running out of natural gas persisted, and this recognition lag supported the continued investment of billions of dollars to expand LNG import facilities (see Figure 6).

3. *New York Times*. "Coal to the Rescue, But Maybe Not Next Winter." Wald, Matthew L. 10 March 2014: http://www.nytimes.com/2014/03/11/business/energy-environment/coal-to-the-rescue-this-time.html?_r=0, retrieved 12 May 2014.

Eventually, evidence of a shale gas revolution became undeniable. However, recognition and adaptation lags continued. Productivity trends in natural gas–directed drilling rigs indicate that only about 400 gas-directed rigs are needed to keep natural gas demand and supply in balance over the long run. Yet operators in the natural gas industry did not fully anticipate this technological trend. Bullish price projections caused the US natural gas–directed rig count to rise from 690 to 1,600 rigs

FIGURE 5

Growth in major US shale plays



Note: Bcf = billion cubic feet.
Source: IHS Energy, Lippmann Consulting

FIGURE 6

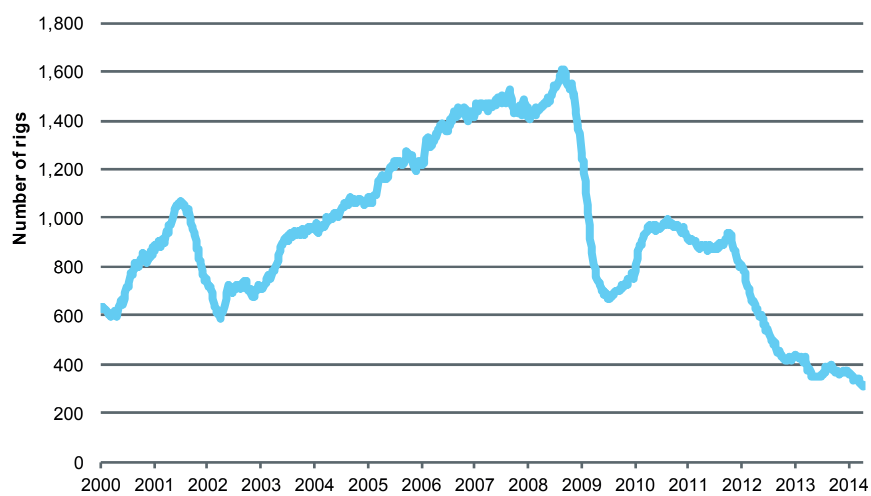
LNG facilities in North America—Existing and proposed (October 2006)

40609-1Source: IHS Energy

between 2002 and 2008. This level of drilling activity created a supply surplus that caused a precipitous decline of up to 85% in the Henry Hub natural gas price from 2008 to 2012. From the 2008 high count, the number of US natural gas–directed rigs dropped over fivefold to 310 by April 2014 (see Figure 7).

FIGURE 7

US gas-directed rig count, 2000–14 YTD



Source: IHS Energy, Baker Hughes © 2014 IHS

Natural gas investment activity also lagged market developments. During this time, the linkage between North American natural gas markets and global markets reversed from an investment hypothesis supporting an expansion of LNG *import* facilities, as shown in Figure 6, to an investment hypothesis involving the expansion of LNG *export* facilities (see Figure 8). At the same time, investment in natural gas pipelines and storage did not keep pace with the shifts in domestic demand, supply, and trade. This asymmetry created vulnerability to low frequency but high impact events, such as colder-than-normal winters that expose gas deliverability constraints and launch record-setting delivered price spikes, as happened in the Northeast in the winters of 2012/13 and 2013/14.

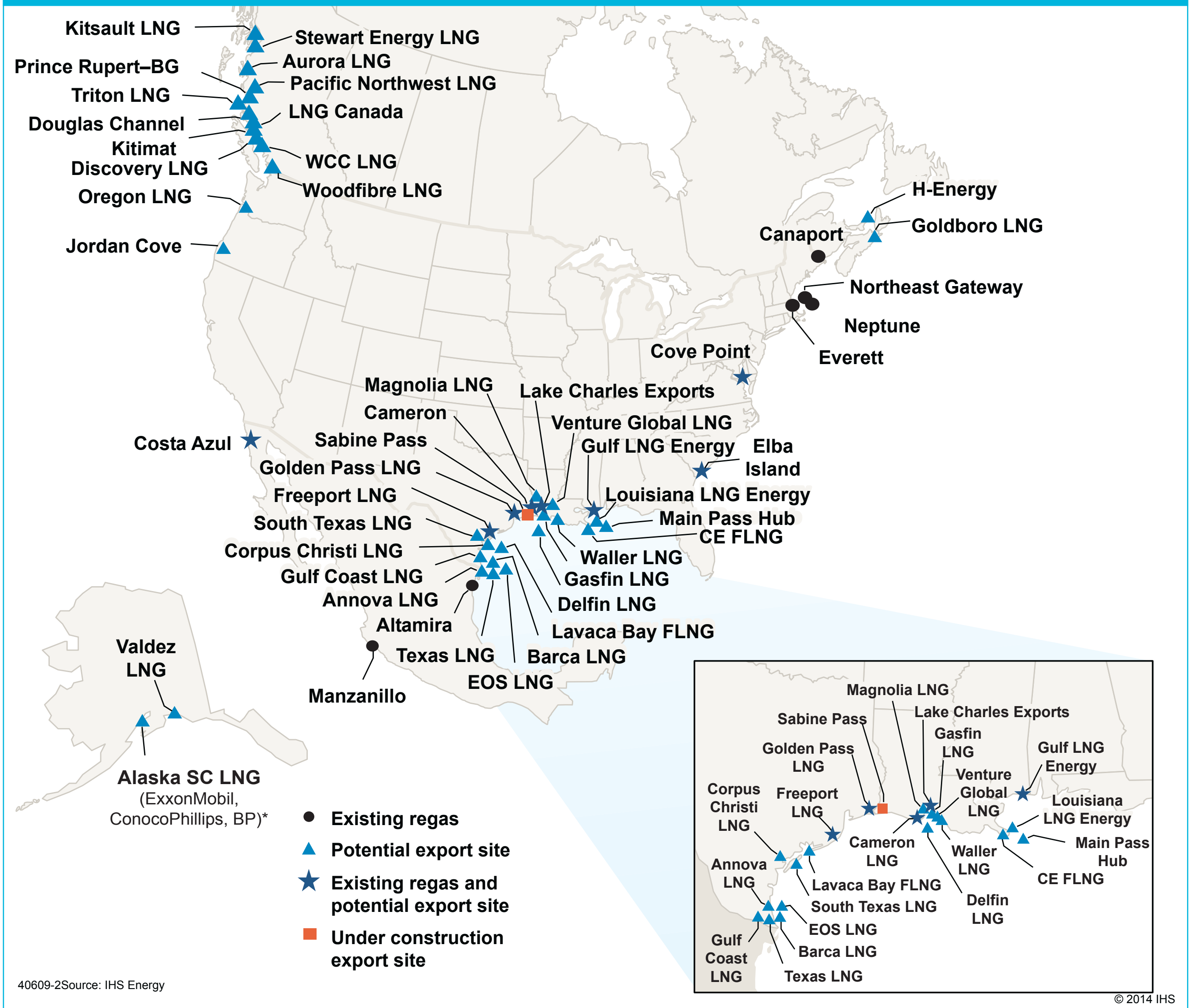
The Northeast delivered natural gas price spikes translated directly into dramatic power production cost run-ups. During the winter of 2013/14, natural gas prices delivered to the New York and PJM power system border hit $140 per MMBtu (at Transco Zone 6, 21 January 2014) and pushed natural gas–fired power production costs up 25-fold from typical levels and well beyond the $1,000 per MWh hourly wholesale power price cap in New York and PJM. This forced the New York Independent System Operator (NYISO) to allow exemptions to market price caps. The Federal Energy Regulatory Commission granted an emergency request to lift wholesale power price caps in PJM and New York. Lifting these price caps kept the lights on but also produced price shocks to 30% of the US power sector receiving monthly power bills in these power systems. The impact moved the 12-month electricity price index (a component of the consumer price index) in the Northeast up 12.7%—the largest 12-month jump in eight years.

The New York Mercantile Exchange (NYMEX) futures contract price strip illustrates how difficult it is to anticipate natural gas price movements. Figure 9 shows the price dynamics over the shale gas era and periodic examples of the NYMEX futures price expectations. The NYMEX future price error pattern indicates a bias toward expecting future natural gas prices to look like those of the recent past. Although these futures prices are often used as an indicator of future natural gas price movements, they have nonetheless proven to be a poor predictor.

The complex drivers of natural gas price dynamics continue to apply in the shale gas era. Prudent planning requires recognition that natural gas price movements remain hard to forecast, affected by multiyear

FIGURE 8

US lower-48 regasification facilities and filed liquefaction projects



40609-2Source: IHS Energy

investment cycles that lag market developments, subject to seasonality, and capable of severe short-run price volatility.

Natural gas price cycles during the shale gas era and the recent extreme volatility in natural gas prices are clear evidence that the benefits of increased natural gas use for power generation need to be balanced against the costs of natural gas's less predictable and more variable production costs and fuel availability.

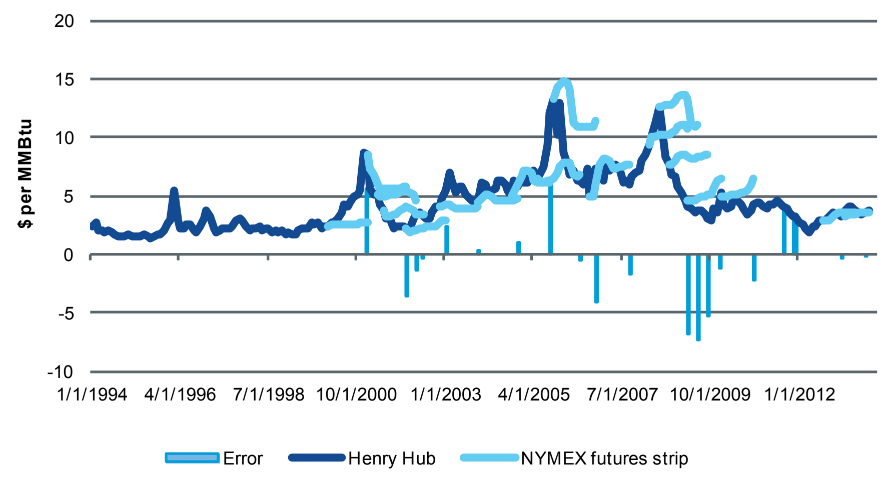
The natural gas–fired generation share is second only to the coal-fired generation share. One of the primary reasons that fuel diversity is so valuable is because natural gas prices and coal prices do not move together.

Significant variation exists in the price of natural gas relative to the price of coal delivered to US power generators (see Figure 10). The dynamics of the relative price of natural gas to coal are important because relative prices routinely change which power plants provide the most cost-effective source of additional power supply at any point in time.

The relative prices of natural gas to coal prior to the shale gas revolution did not trigger as much cost savings from fuel substitution as the current relative prices do. From 2003 to 2007 the price of natural gas was four times higher than the price of coal on a Btu basis. Under these relative price conditions, small changes in fuel prices did not alter the position of coal-fired generation as the lower-cost resource for power generation. The shale gas revolution brought gas prices to a more competitive level and changed the traditional relative relationship between gas and coal generation. As Table 1 shows, the 2013 dispatch cost to produce electricity at the typical US natural gas–fired power plant was equivalent to the dispatch cost at the typical US coal-fired power plant with a delivered natural gas price of $3.35 per MMBtu, about 1.39 times the delivered price of coal. Current price changes move the relative price of natural gas to coal around this average equivalency level and create more generation substitution than has historically occurred.

FIGURE 9

Henry Hub and NYMEX futures, 1994–2013



Source: IHS Energy

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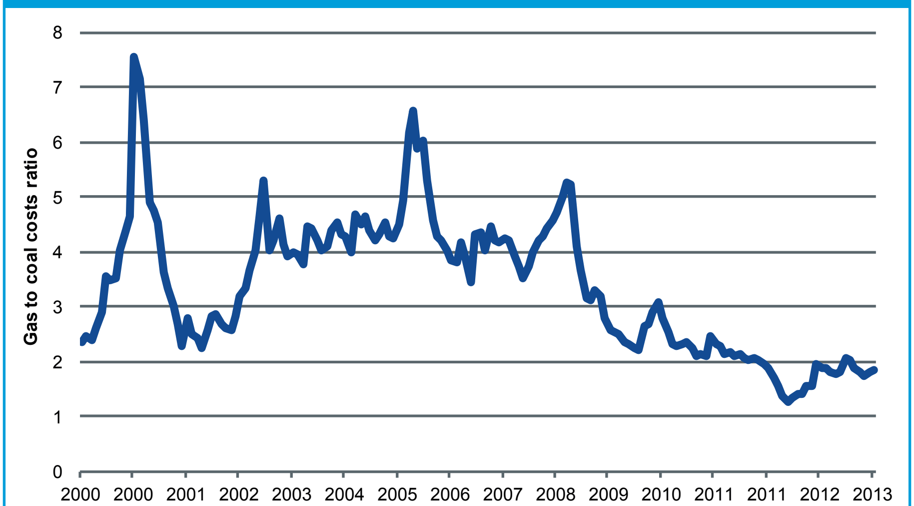
FIGURE 10

Ratio of delivered gas to delivered coal costs, 2000–13



Note: ratio of costs per MMBtu.
Source: IHS Energy, Ventyx Velocity Suite

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The average equivalency level triggers cost savings from substitution within the generation mix. Current relative prices frequently move above and below this critical relative price level. Consequently, slight movements in either coal or natural gas prices can have a big impact on which generation resource provides the most cost-effective source of generation at any given point in time.

Coal price dynamics differ from natural gas price movements. The drivers of coal price dynamics include rail and waterborne price shifts, changes in coal inventory levels, and mine closures and openings. In addition, international coal trade significantly influences some coal prices. For example, when gas prices began to fall in 2008–12, the natural gas displacement of coal in power generation caused Appalachian coal prices also to drop. However, the coal price drop was slower and less severe than the concurrent natural gas price drop because of the offsetting increase in demand for coal exports, particularly for metallurgical coal. Linkages to global coal market prices were significant even though only about one-quarter of Appalachian coal production was involved in international trade. The implication is that as global trade expands, the influence of international trade on domestic fuel prices may strengthen.

TABLE 1

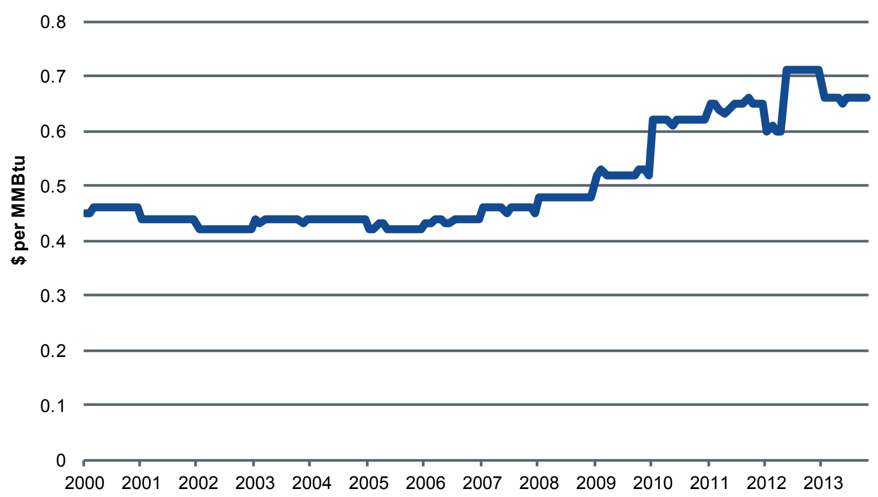
Typical generating units

	Typical coal unit	Typical CCGT unit
Size, MW	218	348
Heat rate, Btu/kWh	10,552	7,599
Fuel cost, $/MMBtu	$2.41	$4.46
Fuel cost, $/MWh	$25.43	$33.89
Variable O&M, $/MWh	$4.70	$3.50
Lbs SO_2/MWh (with wet FGD)	1.16	0
SO_2 allowance price, $/ton	70	70
Lbs NO_X/MWh	0.74	0.15
NO_X allowance price, $/ton	252	252
SO_2,NO_X emissions cost, $/MWh	0.13	0.02
Short-run marginal cost, $/MWh	$30.26	$37.41
Breakeven fuel price, $/MMBtu	$2.41	$3.35

Note: kWh = kilowatt-hour(s); O&M = operation and maintenance (costs); SO_2 = sulfur dioxide; NO_X = nitrogen oxides; CCGT = combined-cycle gas turbine.
Source: IHS Energy

FIGURE 11

Nuclear fuel prices, 2000–13



Source: IHS Energy, Ventyx Velocity Suite © 2014 IHS

Nuclear fuel prices are also dynamic, and are different from fossil fuel prices in two ways (see Figure 11). Nuclear fuel cost is a relatively smaller portion of a nuclear plant's overall cost per kilowatt-hour. Also nuclear fuel prices have a different set of drivers. The primary drivers of nuclear fuel price movements include uranium prices, enrichment costs, and geopolitical changes in nuclear trade. These drivers produce price dynamics dissimilar to those of either natural gas or coal. As a result, nuclear fuel price movements are not strongly correlated to fossil fuel price movements.

Diversity: The portfolio effect

A diverse fuel and technology portfolio is a cornerstone for an effective power production risk management strategy. If prices for alternative fuels moved together, there would be little value in diversity. But relative power production costs from alternative fuels or technologies are unrelated and inherently unstable. As a result, the portfolio effect in power generation exists because fuel prices do not move together, and thus changes in one fuel price can offset changes in another. The portfolio effect of power generation fuel diversity is significant because the movements of fuel prices are so out of sync with one another.

The "correlation coefficient" is a statistical measure of the degree to which fuel price changes are related to each other. A correlation coefficient close to zero indicates no similarity in price movements. Correlation coefficients above 0.5 are considered strong correlations, and values above 0.9 are considered very strong correlations. Power production input fuel price changes (natural gas, coal, and nuclear) are not highly correlated and consequently create the basis for a portfolio approach to fuel price risk management (see Table 2).

TABLE 2

Delivered monthly fuel price correlations, 2000–13	
Coal/natural gas	0.01
Natural gas/nuclear	(0.35)
Coal/nuclear	0.85

Source: IHS Energy

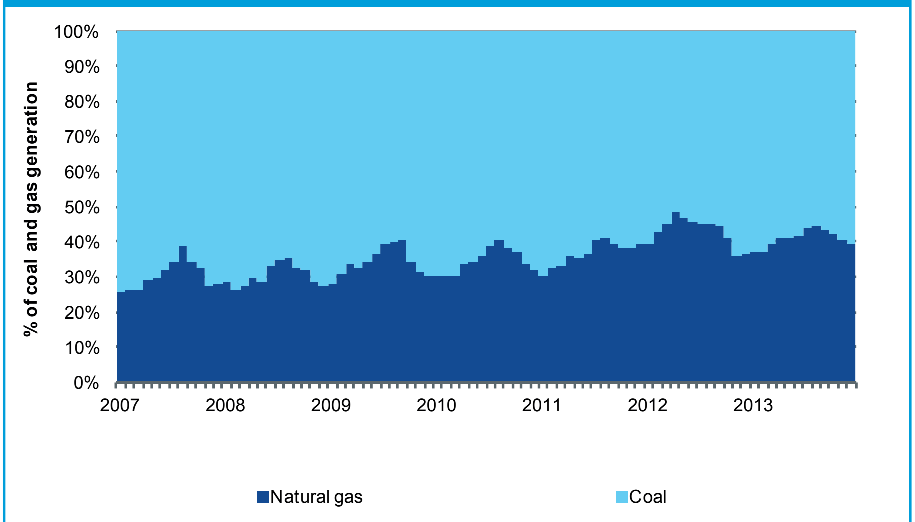
Diversity: The substitution effect

A varied portfolio mitigates power production cost risk because fuel diversity provides the flexibility to substitute one source of power for another in response to relative fuel price changes. Therefore, being able to substitute between alternative generation resources reduces the overall variation in production costs.

Substitution benefits have proven to be substantial. In the past five years, monthly generation shares for natural gas–fired generation were as high as 33% and as low as 19%. Similarly, monthly generation shares for coal-fired generation were as high as 50% and as low as 34%. The swings were driven primarily by a cost-effective alignment of fuels and technologies to consumer demand patterns and alterations of capacity utilization rates in response to changing relative fuel costs. Generation shares shifted toward natural gas–fired generation when relative prices favored natural gas and shifted toward coal-fired generation when relative prices favored coal. Figure 12 shows the recent flexibility in the utilization share tradeoffs between only coal-fired and natural gas–fired generation in the United States.

FIGURE 12

Coal and natural gas generation, 2007–13



Source: IHS Energy

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Diversity benefits differ by technology

All types of generating fuels and technologies can provide the first dimension of risk management—the *portfolio effect*. However, only some types of fuels and technologies can provide the second dimension of risk management—the *substitution effect*. Power plants need to be dispatchable to provide the substitution effect in a diverse portfolio. As a result, the benefits of expanding installed capacity diversity by adding nondispatchable resources such as wind and solar generating technologies are less than the equivalent expansion of power capacity diversity with dispatchable power plants such as biomass, conventional fossil-fueled power plants, reservoir hydro, and nuclear power plants. Therefore, not all diversity in the capacity mix provides equal benefits.

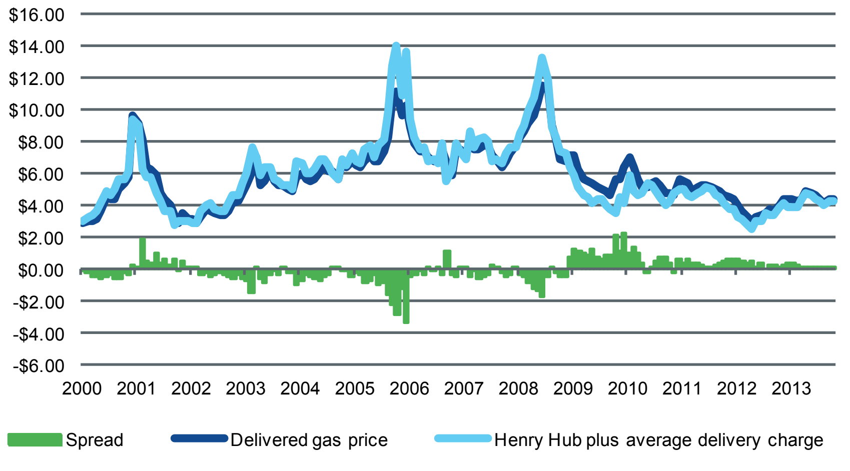
Diversity is the best available power cost risk management tool

A diverse portfolio is the best available tool for power generation cost risk management. Other risk management tools such as fuel contracts and financial derivatives complement fuel and technological diversity in power generation but fall far short of providing a cost-effective substitute for power supply diversity.

Contracts are tools available to manage power production cost risk. These tools include short-run contracts, including NYMEX futures contracts, as well as long-term contracts spanning a decade or more. Power generators have traditionally covered some portion of fuel needs with contracts to reduce the variance of delivered fuel costs. To do this, generators balance the benefits of using contracts or financial derivatives against the costs. With such assessment, only a small percentage of natural gas purchases are under long-term contracts or hedged in the futures markets. Consequently, the natural gas futures market is only liquid (has many buyers and sellers) for a few years out.

FIGURE 13

Power generation delivered gas price versus Henry Hub (plus delivery), 2000–13



Source: IHS Energy, Ventyx Velocity Suite © 2014 IHS

The degree of risk management provided by contracts is observed in the difference between the reported delivered price of natural gas to power generators and the spot market price plus a typical delivery change. Contract prices along with spot purchases combine to determine the reported delivered price of natural gas to power generators. Delivered prices are typically about 12% higher than the Henry Hub spot price owing to transport, storage, and distribution costs, so this percentage may be used to approximate a delivery charge. Figure 13 compares the Henry Hub spot price plus this typical delivery charge to the reported delivered price of natural gas to power producers.

A comparison of the realized delivered price to the spot price plus a delivery charge shows the impact of contracting on the delivered price pattern. Natural gas contracts provided some protection from spot price highs and thus reduced some variation of natural gas prices compared to the spot market price plus transportation. Over the past 10 years, contracting reduced the monthly variation (the standard deviation) in the delivered price of natural gas to the power sector by 24% compared to the variation in the spot price plus delivery charges at the Henry Hub. Although fuel contracts are part of a cost-effective risk management strategy, the cost/benefit trade-offs of using contracts limit the application of these tools in a cost-effective risk management strategy.

Using a contract to lock into volumes at fixed or indexed prices involves risks and costs. Contracting for fuel creates volume risk. A buyer of a contract is taking on an obligation to purchase a given amount of fuel, at a given price, and at a future point in time. From a power generator's perspective, the variations in aggregate power consumer demand and relative prices to alternative generating sources make predicting the amount of fuel needed at any future point in time difficult. This difficulty increases the further out in time the contracted fuel delivery date. If a buyer ends up with too much or too little fuel at a future point in time, then the buyer must sell or buy at the spot market price at that time.

Contracting for fuel creates price risk. A buyer of a fuel contract locks into a price at a future point in time. When the contract delivery date arrives, the spot market price for the fuel likely differs from the contract price. If the contract price ends up higher than the spot market price, then the contract provided price certainty but also created a fuel cost that turned out to be more expensive than the alternative of spot market purchases. Conversely, if the spot market price turns out to be above the contract price, then the buyer has realized a fuel cost savings.

Past price relationships also illustrate the potential for gains and losses from contracting for natural gas in an uncertain price environment. When the spot market price at Henry Hub increased faster than expected, volumes contracted at the previously lower expected price produced a gain. For example, in June 2008 the delivered cost of natural gas was below that of the spot market. Conversely, when natural gas prices fell faster than anticipated, volumes contracted at the previously higher expected price produced a loss. For example in June 2012, the delivered cost of natural gas was above that of the spot market purchases.

The combination of volume and price risk in fuel contracting makes buying fuel under contract a speculative activity, capable of generating gains and losses depending on how closely contract prices align with spot market prices. Therefore, cost-effective risk management requires power generators to balance the benefits of gains from contracting for fuel volumes and prices against the risk of losses.

Managing fuel price risk through contracts does not always involve the physical delivery of the fuel. In particular, a futures contract is typically settled before physical delivery takes place, and thus is referred to as a financial rather than a physical hedge to fuel price uncertainty. For example, NYMEX provides a standard contract for buyers and sellers to transact for set amounts of natural gas capable of being delivered at one of many liquid trading hubs at a certain price and a certain date in the future. Since the value of a futures contract depends on the expected future price in the spot market, these futures contracts are derivatives of the physical natural gas spot market.

The potential losses facing a fuel buyer that employs financial derivatives create a risk management cost. Sellers require that buyers set aside funds as collateral to insure that potential losses can be covered. Market regulators want these guarantees in place as well in order to manage the stability of the marketplace. Recently, as part of reforms aimed at improving the stability of the financial derivatives markets, the Dodd-Frank Act increased these collateral requirements and thus the cost of employing financial derivatives.

Outside of financial derivatives, fuel deliverability is an important consideration in evaluating power cost risk management. Currently, natural gas pipeline expansion requires long-term contracts to finance projects. Looking ahead, the fastest growing segment of US natural gas demand is the power sector and, as described earlier, this sector infrequently enters into long-term natural gas supply contracts that would finance new pipelines. Consequently, pipeline expansions are not likely to stay in sync with power generation natural gas demand trends.

The prospect of continued periodic misalignments between natural gas deliverability and natural gas demand makes price spikes a likely feature of the future power business landscape. The nominal volume of long-term fuel contracts and the costs and benefits of entering into such contracts limit the cost-effective substitution of contracts for portfolio diversity. Therefore, maintaining or expanding fuel diversity remains a competitive alternative to natural gas infrastructure expansion.

Striking a balance between the costs and benefits of fuel contracting makes this risk management tool an important complement to a diverse generation portfolio but does not indicate that it could provide a cost-effective substitute for power supply diversity.

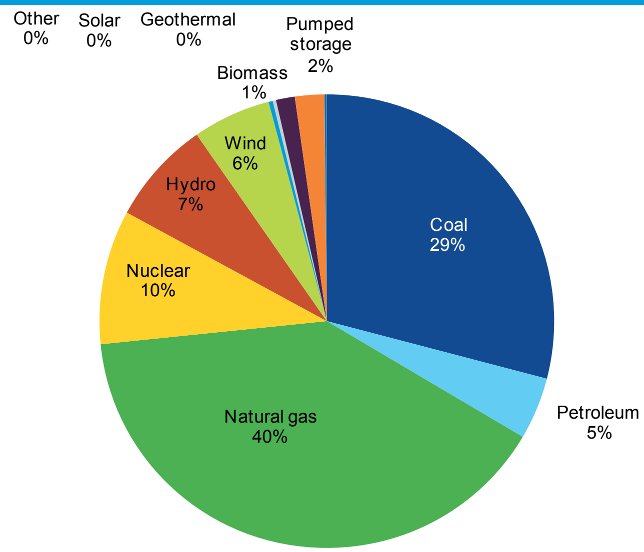
A starting point taken for granted

US power consumers benefit from the diverse power supply mix shown in Figure 14. Simply inheriting this diverse generation mix based on fuel and technology decisions made decades ago makes it easy for current power stakeholders to take the benefits for granted. This underappreciation of power supply diversity creates an energy policy challenge because if the value of fuel and technology diversity continues to be taken for granted, then the current political and regulatory process is not likely to properly take it into account when crafting legislation or setting regulations.

As a result, the United States may move down a path toward a less diverse power supply without consumers realizing the value of power supply diversity until it is gone. For example, if the US power sector had been all natural gas–fired during the shale gas era to date, the average fuel cost for power would have been over twice as high, and month-to-month power bill variation (standard deviation) would have been three times greater (see Table 3). This estimate itself is conservative because the additional demand from power generation would have likely put significant upward pressure on gas prices.

FIGURE 14

US installed capacity (1,063 GW), 2012



Source: US Energy © 2014 IHS

TABLE 3

The impact of fuel diversity: Power production fuel costs
(Actual versus all gas generation mix, 2000–13 YTD, cents per kWh)

	Henry Hub	All power sector fuel costs
Average	5.09	2.29
Maximum	11.02	4.20
Minimum	2.46	1.21
Standard deviation	1.63	0.55

Note: Converted the Henry Hub dollar per MMBtu price to cents per kWh using the average reported heat rate for all operating natural gas plants in the respective month.
Data source: Ventyx Velocity Suite.

Source: IHS Energy

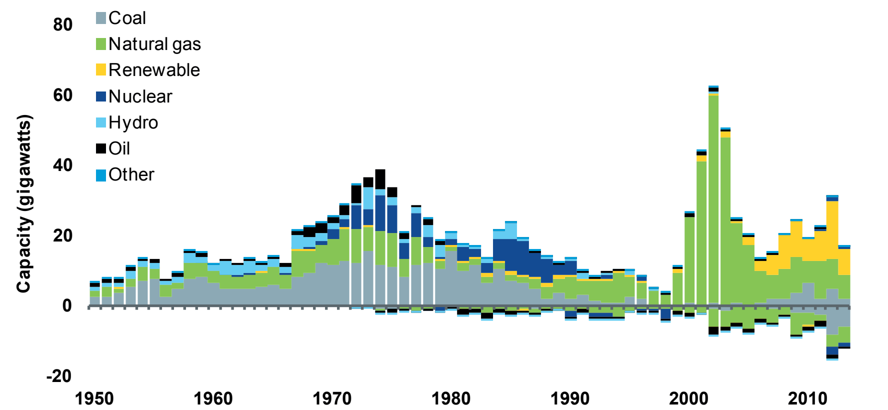
Trends in the US generation mix

The current diverse fuel and technology mix in US power supply did not come about by accident. The US generation mix evolved over many decades and reflects the fuel and technology decisions made long ago for power plants that typically operate for 30 to 50 years or more. Consequently, once a fuel and technology choice is made, the power system must live with the consequences—whatever they are—for decades.

US power supply does not evolve smoothly. The generation mix changes owing to the pace of power plant retirements, the error in forecasting power demand, price trends and other developments in the energy markets, and the impacts of public policy initiatives. All three of these factors unfold unevenly over time. The current diverse generation mix evolved from multiyear cycles of capacity additions that were typically dominated by a particular fuel and technology (see Figure 15). The swings in fuel and technology choice do not indicate a lack of appreciation for diverse power supply. Instead, they show that given the size of the existing supply base, it takes a number of years of homogenous supply additions to move the overall supply mix a small proportion. Therefore, altering the overall mix slightly required a number of years of adjustment.

FIGURE 15

US generating capacity additions and retirements, 1950–2013



Source: IHS Energy, Ventyx Velocity Suite

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The uneven historical pattern of capacity additions is important because the future pattern of retirements will tend to reflect the previous pattern of additions as similarly aged assets reach the end of their useful lives. For example, current retirements are disproportionately reducing the coal and nuclear shares in the capacity mix, reflecting the composition of power plants added in the 1960s through 1980s. Current power plant retirements are about 12,000 MW per year and are moving the annual pace of retirements in the next decade to 1.5 times the rate of the past decade.

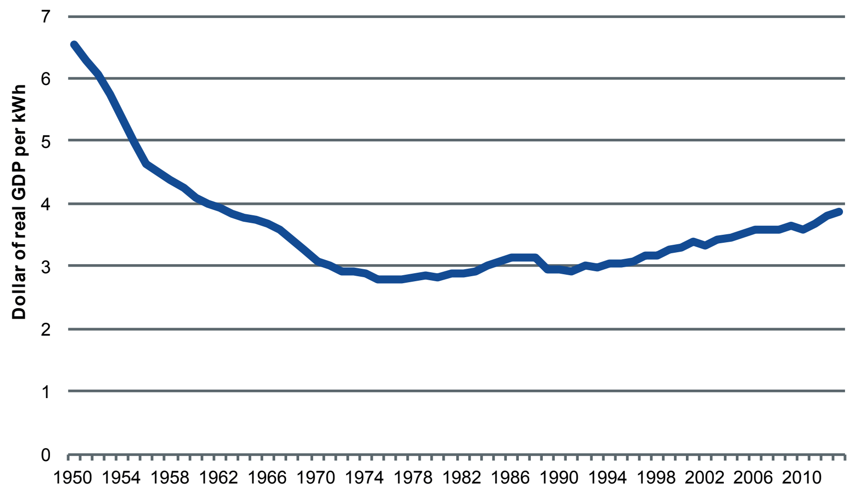
Power plant retirements typically need to be replaced because electricity consumption continues to increase. Although power demand increases are slowing compared to historical trends and compared to the growth rate of GDP, the annual rate of change nevertheless remains positive. US power demand is expected to increase between 1.0% and 2.5% each year in the decade ahead, averaging 1.5%.

The expected pace of US power demand growth reflects a number of trends. First, US electric efficiency has been improving for over two decades. Most appliances and machinery have useful lives of many years. As technology improves, these end uses get more efficient. Therefore, overall efficiency typically increases as appliances and machinery wear out and are replaced. On the other hand, the number of electric end uses keeps expanding and the end-use penetration rates keep increasing owing to advances in digital and communication technologies that both increase capability and lower costs. These trends in existing technology turnover and new technology adoption produce a steady rate of change in electric end-use efficiency (see Figure 16).

Underlying trends in power demand are often masked by the influences of variations in the weather and the business cycle. For example, US electric output in first quarter 2014 was over 4% greater than in the same period one year ago owing in part to the influence of the polar vortex. Therefore, trend rates need to compare power consumption increases either between points in time with similar weather conditions or on a weather-normalized basis. Similarly, power demand trends can be misleading if compared without taking the business cycle into account. Figure 17 shows the trend rate of growth in power use from the previous business cycle peak to peak and tough to trough. Overall, power consumption increased by between 0.5 and 0.6 of the rate of increase in GDP. Looking ahead, GDP is expected to increase on average 2.5% annually through 2025 and thus is likely to produce a trend rate of electric consumption of around 1.5% annually. This US power demand growth rate creates a need for about 9 GW of new power supply per year, for a total of 1,140 GW by 2025.

FIGURE 16

US electric efficiency, 1950–2013



Note: BEA reports Real GDP in 2009 dollars.
Source: IHS Energy, EIA, BEA

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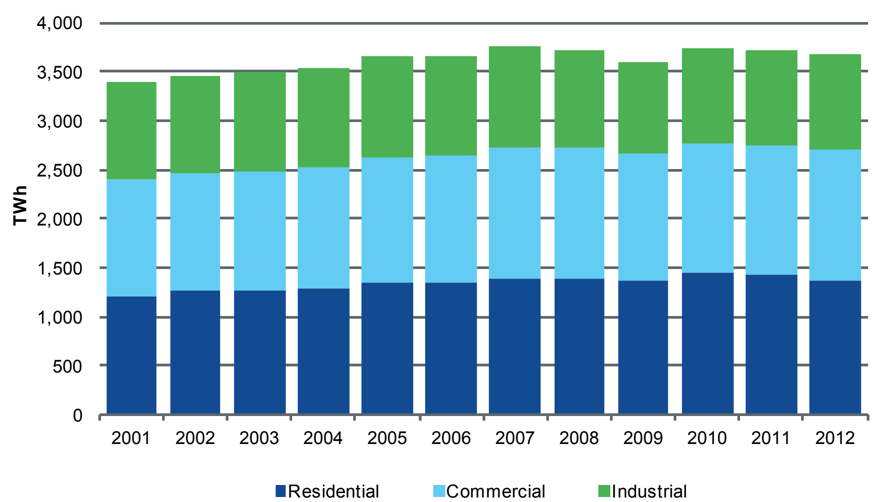
FIGURE 17

US electricity sales by customer class, 2001–12



Note: TWh = terawatt-hour(s).
Source: IHS Energy, EIA

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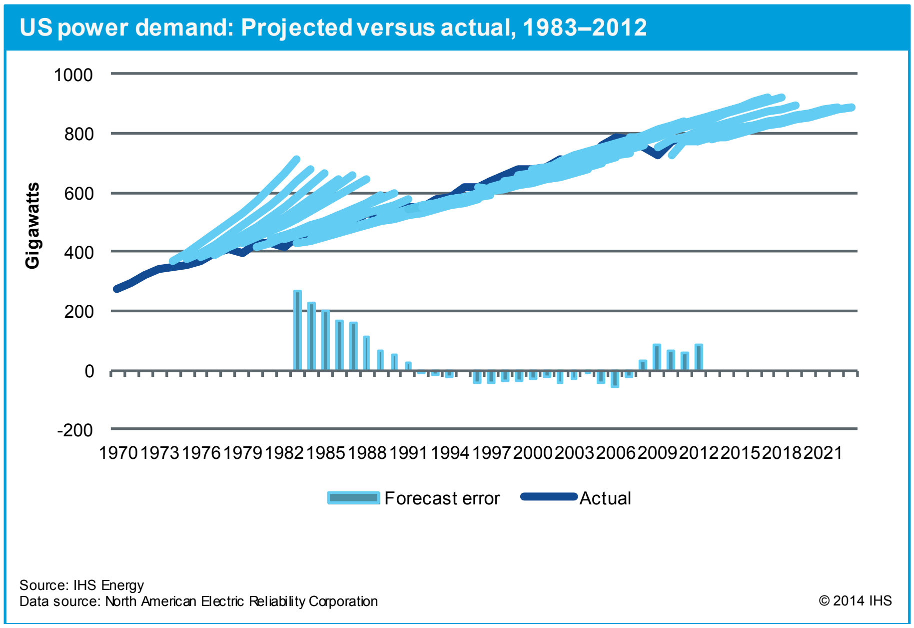
Annual power supply additions do not typically unfold simultaneously with demand increases. Historically, changes in power supply are much more pronounced than the changes in power demand. This uneven pace of change in the capacity mix reflects planning uncertainty regarding future power demand and a slow adjustment process for power supply development to forecast errors.

Future electric demand is uncertain. Figure 18 shows a sequence of power industry forecasts of future demand compared to the actual demand. The pattern of forecast errors indicates that electric demand forecasts are slow to adjust to actual conditions: overforecasts tend to be followed by overforecasts, and underforecasts tend to be followed by underforecasts.

FIGURE 18



Forecasting uncertainty presents a challenge because fuel and technology decisions must be made years in advance of consumer demand to accommodate the time requirements for siting, permitting, and constructing new sources of power supply. As a result, the regional power systems are subject to momentum in power plant addition activity that results in capacity surpluses and shortages. Adjustment to forecast overestimates is slow because when a surplus becomes evident, the capital intensity of power plants creates an accumulating sunk-cost balance in the construction phase of power supply development. In this case, there is an economic incentive to finish constructing a power plant because the costs to finish are the relevant costs to balance against the benefits of completion. Conversely, if a shortage becomes evident, new peaking power plants take about a year to put into place under the best of circumstances. Consequently, the forecast error and this lagged adjustment process can produce a significant over/underinstallment of new capacity development versus need. These imbalances can require a decade or more to work off in the case of a capacity overbuild and at least a few years to shore up power supply in the case of a capacity shortage.

The pace and makeup of power plant additions are influenced by energy policies. The current installed capacity mix reflects impacts from the implementation of a number of past policy initiatives. Most importantly, 35 years ago energy security was a primary concern, and the energy policy response included the Fuel Use Act (1978) and the Public Utilities Regulatory Policy Act (1978). These policies limited the use of natural gas for power generation and encouraged utility construction of coal and nuclear generating resources as well as nonutility development of cogeneration. Public policy championed coal on energy security grounds—as a safe, reliable, domestic resource.

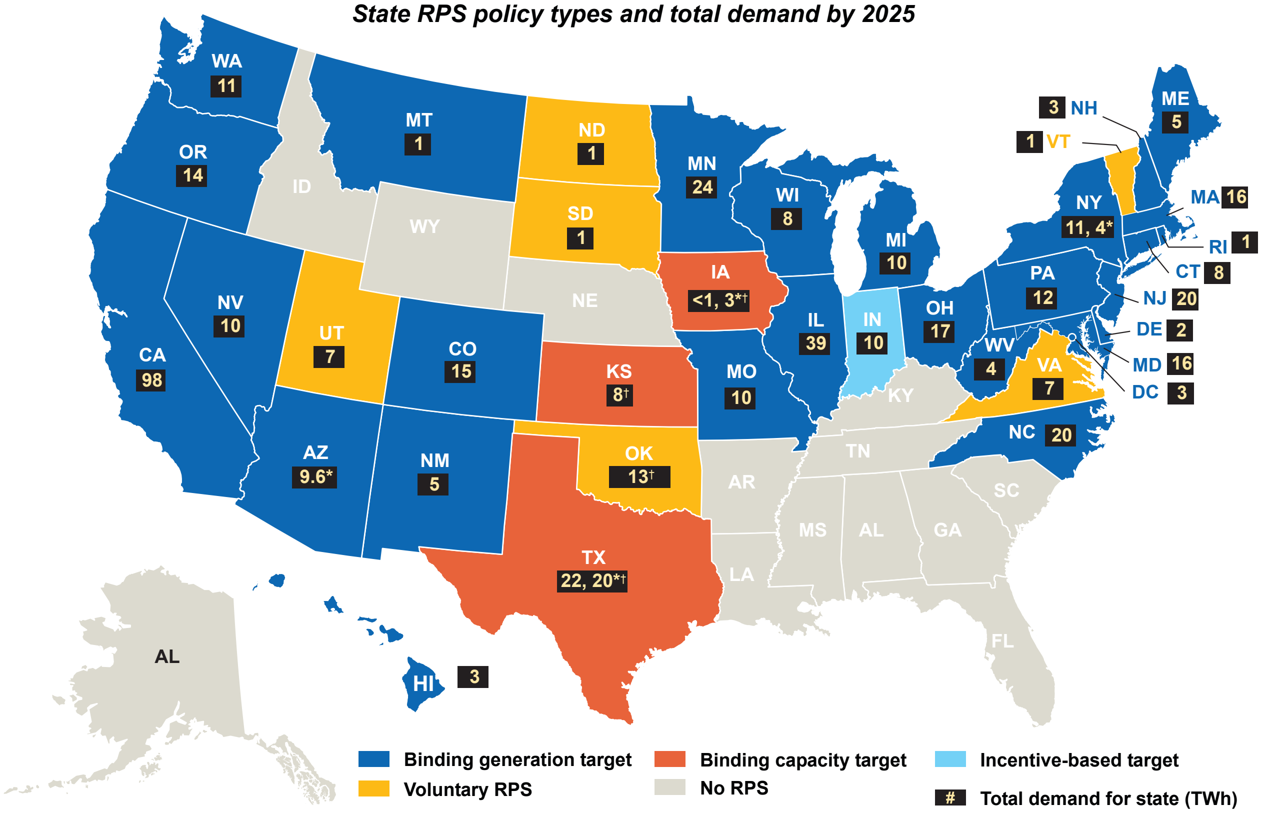
The influence of energy policy on power plant fuel and technology choice is dynamic. For example, as natural gas demand and supply conditions changed following the passage of the Fuel Use Act, the limits on natural gas use for power generation were eventually lifted in 1987. Whereas the Fuel Use Act banned a fuel and technology, other policy initiatives mandate power generation technologies. Energy policies designed to address the climate change challenge created renewable power portfolio requirements in 30 states (see Figure 19).

As states work to implement renewable generation portfolio standards, the complexity of power system operations becomes evident and triggers the need for renewable integration studies. These studies generally find that the costs to integrate intermittent power generation resources increase as the generation share of these resources increases. Some integration studies go so far as to identify the saturation point for wind resources based on their operational characteristics. A wind integration study commissioned by the

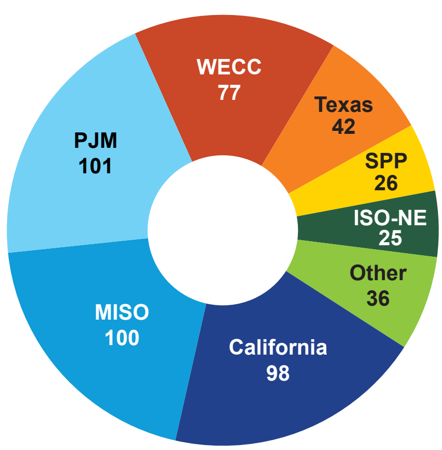
FIGURE 19

The outlook for US State RPS demand to 2025—Total demand: State policy and targets

State RPS policy types and total demand by 2025



Total RPS demand by region (TWh)



30 US states plus the District of Columbia have enacted binding renewable energy targets, and seven others have adopted incentive-based or voluntary targets. These 37 states account for 74% of US retail power sales.

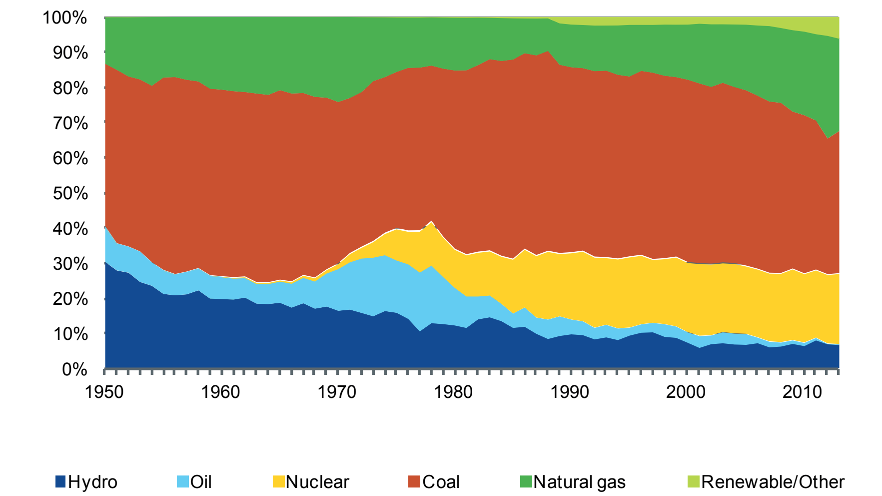
40609-3
Note: *States include both mandatory and voluntary targets; first number reflects mandatory target, second number reflects additional voluntary targets (of state, municipalities, or other political divisions/utilities).
†Capacity targets have been converted to generation for comparison using estimated regional capacity factors. All quantities reflect primary renewables; see page 2 for additional notes
Source: IHS Emerging Energy Research

power system operator in New England estimated the saturation point for wind in the power system (24% generation share) as well as the additional resources that would be needed to integrate more wind resources.[4] Similarly, a wind integration study by the power system operator in California found that problems were ahead for the California power system because the number of hours when too much wind generation was being put on the grid was increasing. The study noted higher costs were ahead as well because additional resources would be needed to integrate expected additional wind resources planned to meet the renewable portfolio requirements in place.[5] Many of the impacts on the US generation mix from renewable power portfolio requirements are yet to come as higher generation or capacity share mandates become binding in many states in the next few years.

The United States is at a critical juncture because current trends in power plant retirements, demand and supply balances, and public policies are combining to accelerate change in the US generation mix, as shown in Figure 20. In 2013, increases in demand, power plant retirements, and renewable mandates resulted in around 15,800 MW of capacity additions. In the decade ahead, these increasing needs will require power supply decisions amounting to 15% of the installed generating capacity in the United States. In addition, public policies are expected to increase the share of wind and solar generation, and forthcoming regulations from the Environmental Protection Agency (EPA) regarding conventional power plant emissions as well as greenhouse gases (GHG) could significantly increase power plant retirements and accelerate changes further. Altogether, changes in US generating capacity in the next two decades could account for more than one-third of installed capacity.

FIGURE 20

US power generation: shares by fuel, 1950–2013



Source: IHS Energy, EIA

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Threat to power generation diversity: Complacency

Threats to maintaining diversity in power production do not come from opposition to the idea itself, but rather from the complacency associated with simply taking diversity for granted. The familiar adage of not putting all your eggs in one basket is certainly aligned with the idea of an all-of-the-above energy policy. Four decades of experience demonstrates the conclusion that the government should not be picking fuel or technology winners, but rather should be setting up a level playing field to encourage competitive forces to move the power sector toward the most cost-effective generation mix. Nevertheless, in a striking contrast,

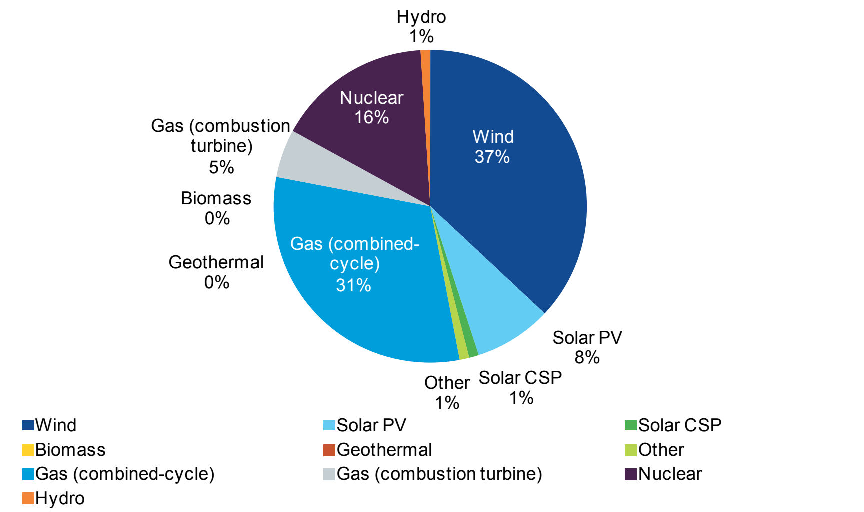
4. *New England Wind Integration Study* produced for ISO New England by GE Energy Applications and Systems Engineering, EnerNex Corporation, and AWS Truepower, 5 December 2010. Accessed 16 April 2014 (http://www.uwig.org/newis_es.pdf).

5. "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS." California ISO, 31 August 2010, downloaded from www.caiso.com/2804/2804d036401f0.pdf.

the value of fuel diversity to the end use consumer is not internalized in current power plant decision making. A 2013 review of over eighty integrated resource plans (IRPs) found that many reference fuel diversity but only a few of them refer to it as a risk, and none of them quantify the value of fuel diversity to incorporate it into the decision process.[6] Additionally, environmental policy initiatives do not seem to accommodate diversity issues. Therefore, one power plant decision after another is revealing a de facto energy policy to move away from oil, coal, and nuclear generation and reduce hydroelectric capability, and instead build relatively low utilization wind and solar resources backed up by natural gas–fired generating units (see Figure 21).

FIGURE 21

US capacity under construction: 34,620 MW



Notes: Note: CSP = concentrating solar power, PV = photovoltaic. Data as of April 2014.
Source: IHS Energy and Ventyx Velocity Suite

Threat to power generation diversity: The "missing money"

Fuel diversity is threatened as well by the inability of power markets to evolve market rules and institutions to address the "missing money" problem in competitive power generator cash flows. The missing money problem in power markets is the latest manifestation of a long-standing problem in a number of industries, including railroads, airlines, and power, where competitive markets fail to balance demand and supply at market-clearing prices high enough to support the full cost of supply.

Power markets have a missing money problem because they do not have all of the necessary conditions to produce a textbook competitive marketplace. The textbook marketplace has suppliers who maximize their profits by expanding output up to the point where their short-run marginal cost (SRMC) of production equals the market-clearing price. This means that an aggregation of rival suppliers' SRMC curves produces the market supply curve. If this market supply curve intersects the market demand curve at a price too low to support the full cost of new supply (long-run marginal cost [LRMC]), then suppliers will not expand productive capacity. Instead, they will meet increases in demand by adding more variable inputs to the production process with a fixed amount of capacity. However, doing so increases SRMC, and eventually the market-clearing price rises to the point where it covers the cost of expanding productive capacity. This produces the textbook market equilibrium where demand and supply are in balance at the unique point where market-clearing prices are equal to both SRMC and LRMC.

Several characteristics of the technologies that make up a cost-effective power supply create a persistent gap between SRMCs and LRMCs as production varies. As a result, market-clearing wholesale power prices are below the level needed to support the full cost of power supply when demand and supply are in balance with the desired level of reliability.[7] Consequently, the stable textbook market equilibrium does not exist in an electric power marketplace.

6. See the IHS Energy Insight *Reading the Tea Leaves: Trends in the power industry's future plans.*

7. See the IHS Energy Private Report *Power Supply Cost Recovery: Bridging the missing money gap.*

A simple example of a competitive power market made up entirely of rival wind generators illustrates the missing money problem. The cost profile of wind turbine technologies comprises nearly exclusively upfront capital costs (LRMCs). SRMCs for wind technologies equal zero because the variable input to the power production process is wind, and this input is free. In a competitive market, if wind conditions allow for power production, then rival wind generators will be willing to take any price above zero to provide some contribution to recovering the upfront capital costs. If there is adequate supply to balance demand in a competitive marketplace, then rival wind suppliers will drive the market-clearing price to zero. This is not just a theoretical example. When power system conditions create wind-on-wind competition, then zero or negative market-clearing prices (reflecting the cost of losing the production tax credit) are typically observed. Wind generating technologies are a simple and extreme example of a power generating technology with a persistent gap between SRMCs and LRMCs. But this problem exists to some degree with other power generation technologies.

This technology-based market flaw means that periodic shortage-induced price spikes are the only way for market-clearing prices to close the gap between the SRMC and LRMC. This market outcome does not work because of the inherent contradiction—periodic shortages are needed to keep demand and supply in balance.

The missing money problem threatens cost-effective power supply because when market-clearing power prices are chronically too low to support new power plants, then lower expected cash flows at existing plants cause retirements before it is economic to do so, given replacement costs. It is cost effective to retire and replace a power plant only when its cost of continued operation becomes greater than the cost of replacement. Therefore, a market-clearing power price that reflects the full cost of new power supply is the appropriate economic signal for efficient power plant closure and replacement. Consequently, when this price signal is too low, power plant turnover accelerates and moves power supply toward the reduced diversity case.

"Missing money" and premature closing of nuclear power plants

The Kewaunee nuclear plant in Wisconsin is an example of a power plant retirement due to the missing money problem. Wholesale day-ahead power prices average about $30 per MWh in the Midwest power marketplace. This market does not have a supply surplus, and recently the Midwest Independent System Operator (MISO), the institution that manages the wholesale market, announced that it expects to be 7,500 MW short of generating capacity in 2016.[8] The current market-clearing power price must almost double to send an efficient price signal that supports development of a natural gas–fired combined-cycle power plant.

The Kewaunee power plant needs much less than the cost of a new plant, about $54 per MWh, to cover the costs of continued operation. Kewaunee's installed capacity was 574 MW, and the plant demonstrated effective performance since it began operation in 1974. The plant received Nuclear Regulatory Commission approval for life extension through 2033. Nevertheless, the persistent gap between market prices and new supply costs led Dominion Energy, the power plant's owner, to the October 2012 decision to close the plant because of "low gas prices and large volumes of wind without a capacity market."

Kewaunee is not an isolated case. Other nuclear power plants such as Vermont Yankee provide similar examples. Additionally, a significant number of coal-fired power plants are retiring well before it is economic to do so. For example, First Energy retired its Hatfield's Ferry plant in Ohio on 9 October 2013. This is a large (1,700 MW) power plant with a $33 per MWh variable cost of power production.[9] The going-forward

8. Whieldon, Esther. "MISO-OMS survey of LSEs, generators finds resource shortfall remains likely in 2016." SNL Energy, 6 December 2013. Accessed on 14 May 2014 http://www.snl.com/InteractiveX/ArticleAbstract.aspx?id=26168778. Note: LSE = load-serving entity.

9. Source: SNL Financial data for 2012 operations, accessed 5 May 2014. Available at http://www.snl.com/InteractiveX/PlantProductionCostDetail.aspx?ID=3604.

costs involved some additional environmental retrofits, but the plant had already invested $650 million to retrofit a scrubber just four years prior to the announced retirement.

Reducing diversity and increasing risk

Proposed EPA regulations on new power plants accommodate the carbon footprint of new natural gas–fired power plants but do not accommodate the carbon footprint of any new state-of-the-art conventional coal-fired power plants that do not have carbon capture and storage (CSS). Since the cost and performance of CSS technologies remain uneconomic, the United States is now on a path to eliminating coal-fired generation in US power supply expansion. This move toward a greatly reduced role for coal in power generation may accelerate because the EPA is now developing GHG emission standards for existing power plants that could tighten emissions enough to dramatically increase coal-fired power plant retirements.

The impact of a particular fuel or technology on fuel diversity depends on overall power system conditions. As a general rule, the benefits of fuel diversity from any source typically increase as its share in the portfolio decreases. Oil-fired generation illustrated this principle when it proved indispensable in New England in keeping electricity flowing this past winter. Despite only accounting for 0.2% of US generation, it provided a critical safety valve for natural gas deliverability during the polar vortex. Yet, these oil-fired power plants are not likely to survive the tightening environmental regulations across the next decade. The implication is clear: there is a much higher cost from losing this final 0.2% of oil in the generation mix compared to the cost of losing a small percentage of oil-fired generation back in 1978, when oil accounted for 17% of the US generation mix. Losing this final 0.2% of the generation mix will be relatively expensive because the alternative to meet infrequent surges in natural gas demand involves expanding natural gas storage and pipeline capacity in a region where geological constraints make it increasingly difficult to do so.

Public opinion is a powerful factor influencing the power generation mix. The loss of coal- or oil-fired power plants in the generation mix is often ignored or dismissed because of public opinion. Coal- or oil-fired power plants are generally viewed less favorably than wind and solar resources. In particular, labeling some sources of power as "clean energy" necessarily defines other power generating sources as "dirty energy." This distinction makes many conventional power supply sources increasingly unpopular in the political process. Yet, all sources of power supply employed to meet customer needs have an environmental impact. For example, wind and solar resources require lots of land and must be integrated with conventional grid-based power supply to provide consumers with electricity when the wind is not blowing or the sun is not shining. Therefore, integrating these "clean energy" resources into a power system to meet consumer needs produces an environmental footprint, including a GHG emission rate. The arbitrary distinctions involved in "clean energy" are evident when comparing the emissions profiles of integrated wind and solar power production to that of nuclear power production. A simplistic and misleading distinction between power supply resources is a contributing factor to the loss of fuel diversity.

Edison International provides an example of the impact of public opinion. Antinuclear political pressures in California contributed to the decision in 2013 to prematurely close its San Onofre nuclear power plant. This closure created a need for replacement power supply that is more expensive, more risky, and more carbon intensive.

The going-forward costs of continued operation of the San Onofre nuclear plant were less than the cost of replacement power. Therefore, the closure and replacement of the San Onofre power plant made California power supply more expensive in a state that already has among the highest power costs in the nation. A study released in May 2014 by the Energy Institute at Haas at the University of California Berkeley estimated that closing the San Onofre nuclear power station increased the cost of electricity by $350 million during the first twelve months.[10] This was a large change in power production costs, equivalent to a 13% increase in the total generation costs for the state.

Closing San Onofre makes California power costs more risky. California imports about 30% of its electricity supply. Prior to the closure, nuclear generation provided 18.3% of California generation in 2011, and the San Onofre nuclear units accounted for nearly half of that installed nuclear capacity. The Haas study found that imports increase with system demand but not much, likely owing to transmission constraints, grid limitations, and correlated demand across states. The results imply that the loss of the San Onofre power plant was primarily made up through the use of more expensive generation, as much as 75% of which was out-of-merit generation running to supply energy as well as voltage support. The report's analysis found that up to 25% of the lost San Onofre generation could have come from increased imports of power. The substitute power increases California consumers' exposure to the risks of fossil fuel price movements as well as the risks of low hydroelectric generation due to Western Interconnection drought cycles.

Closing San Onofre makes California power production more carbon intensive. Nuclear power production does not produce carbon dioxide (CO_2) emissions. These nuclear units were a major reason that the CO_2 intensity of California power production was around 0.5 pounds (lb) per kilowatt-hour (kWh). Replacement power coming from in-state natural gas–fired power plants has associated emissions of about 0.9 lb per kWh. Replacement power coming from the rest of the Western Interconnection has associated emissions of 1.5 lb per kWh. Even additional wind and solar power sources in California with natural gas–fired power plants filling in and backing them up have a 0.7 lb per kWh emissions profile. The Haas study found that closing San Onofre caused carbon emissions to increase by an amount worth almost $320 million, in addition to the $350 million in increased electricity prices in the first year. In the big picture, California CO_2 emissions have not declined in the past decade, and the closure of the San Onofre nuclear units will negate the carbon abatement impacts of 20% of the state's current installed wind and solar power supply.

The path toward a less diverse power supply

The relative unpopularity of coal, oil, nuclear, and hydroelectric power plants (compared to renewables), combined with the missing money problem, tightening environmental regulations, and a lack of public awareness of the value of fuel diversity create the potential for the United States to move down a path toward a significant reduction in power supply diversity. Within a couple of decades, the US generation mix could have the following capacity characteristics:

- No meaningful nuclear power supply share
- No meaningful coal-fired power supply share
- No meaningful oil-fired power supply share
- Hydroelectric capacity in the United States reduced by 20%, from 6.6% to 5.3% of installed capacity
- Renewables power supply shares at operational limits in power supply mix: 5.5% solar, 27.5% wind
- Natural gas–fired generation becoming the default option for the remaining US power supply of about 61.7%

10. http://ei.haas.berkeley.edu/pdf/working_papers/WP248.pdf, accessed 30 May 2014.

Comparing the performance of current diverse power supply to this reduced diversity case provides a basis for quantifying the current value of fuel and technology diversity in US power supply.

Quantifying the value of current power supply diversity

A number of metrics exist to compare and contrast the performance of power systems under different scenarios. Three power system performance metrics are relevant in judging the performance of alternative generation portfolios:

- SRMC of electric production (the basis for wholesale power prices)
- Average variable cost of electric production
- Production cost variability

IHS Energy chose a geographic scope for the diversity analyses at the interconnection level of US power systems. The United States has three power interconnections: Electric Reliability Council of Texas (ERCOT), Eastern, and Western. These interconnections define the bounds of the power supply network systems that coordinate the synchronous generation and delivery of alternating current electrical energy to match the profile of aggregate consumer demands in real time.

Analysis at the interconnection level is the minimum level of disaggregation needed to analyze the portfolio and substitution effects of a diverse fuel and technology generation mix. In particular, the substitution effect involves the ability to shift generation from one source of power supply to another. The degree of supply integration within an interconnection makes this possible, whereas the power transfer capability between interconnections does not. The degree of power demand and supply integration within these interconnections creates the incentive and capability to substitute lower-cost generation for higher-cost generation at any point in time. These competitive forces cause the incremental power generation cost-based wholesale power prices at various locations within each interconnection to move together. An average correlation coefficient of monthly average wholesale prices at major trading hubs within each interconnection is roughly 0.8, indicating a high degree of supply linkage within each interconnection.

IHS Energy assessed the current value of fuel diversity by using the most recently available data on the US power sector. Sufficient data were available for 2010 to 2012, given the varied reporting lags of US power system data.

IHS employed its Razor Model to simulate the interactions of demand and supply within each of these US power interconnections from 2010 to 2012. The 2010 to 2012 backcasting analysis created a base case of the current interactions between power demand and supply in US power systems. Appendix B describes the IHS Razor Model and reports the accuracy of this power system simulation tool to replicate the actual performance of these power systems. The high degree of predictive power produced by this model in the backcasting exercise establishes the credibility of using this analytical framework to quantify the impacts of more or less fuel and technology diversity. The macroeconomic impact analysis used the most recently available IHS simulation of the US economy (December 2013) as a base case.

Once this base case was in place, the Razor Model was employed to simulate an alternative case involving a less diverse generation mix. The current generation mix in each of the three interconnections—Eastern, Western, and ERCOT—were altered as follows to produce the reduced diversity case generation:

- The nuclear generating share went to zero.

- The coal-fired electric generating share went to zero.

- The hydroelectric generation share dropped to 3.8%.

- Intermittent wind and solar generation increased its combined base case generation share of about 2% to shares approximating the operational limits—24% in the East, 45% in the West, and 23% in ERCOT—resulting in an overall wind generation share of 21.0% and a solar generation share of 1.5%.

- Natural gas–fired generation provided the remaining generation share in each power system, ranging from about 55% in the West to over 75% in the East and ERCOT, for an overall share of nearly 74%.

Differences between the performance metrics of the current diverse generating portfolio simulation and the reduced diversity case simulation provide an estimate for the current value of fuel diversity. The differences in the level and variance of power prices were fed through to the IHS US macroeconomic model to quantify the broader economic impacts of the higher and more varied power prices and shifts in capital deployment associated with the reduced diversity case.

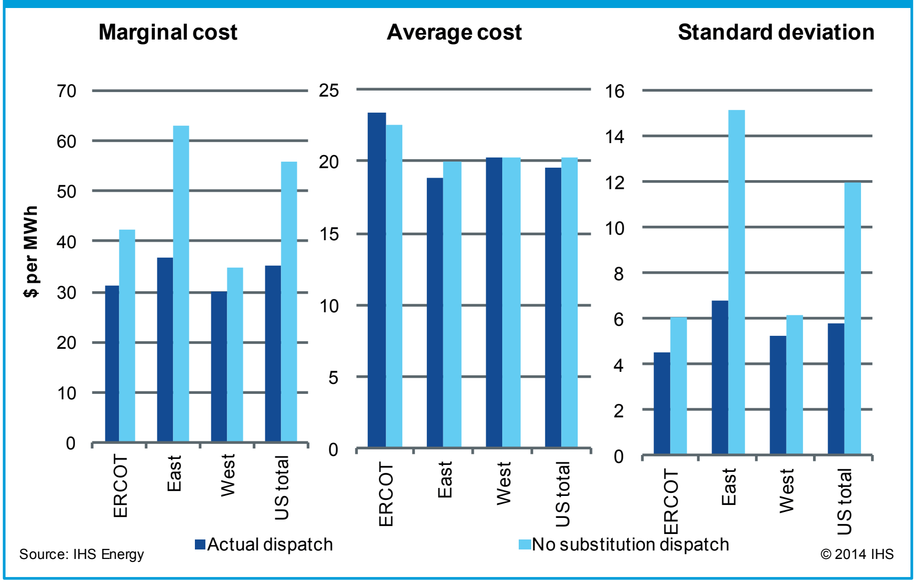
Quantification of the impact of fuel diversity within the US power sector involved a two-step process. The first step quantifies the current value of the substitution effect enabled by a diverse power generating portfolio. The second step quantified the additional value created by the portfolio effect.

The value of the substitution effect

The first step alters the base case by holding relative fuel prices at the average level across 2010 to 2012. Doing this removes the opportunity to substitute back and forth between generation resources based on changes to the marginal cost of generation. This case maintains a portfolio effect but eliminates the substitution effect in power generation. The difference between this constant relative fuel price case and the base case provides an estimate of the current value of the substitution effect provided by the current diverse power generation fuel mix. The results show significantly higher fuel costs from a generation mix deprived of substitution based on fuel price changes. The substitution effects in the current diverse US power generating portfolio reduced the fuel cost for US power production by over $2.8 billion per year. In just the three years of the base case, US power consumers realized nearly $8.5 billion in fuel savings from the substitution effect. Figure 22 shows the results of this first step in the analysis for each interconnection and the United States as a whole.

FIGURE 22

Actual dispatch versus no substitution dispatch: Cost results



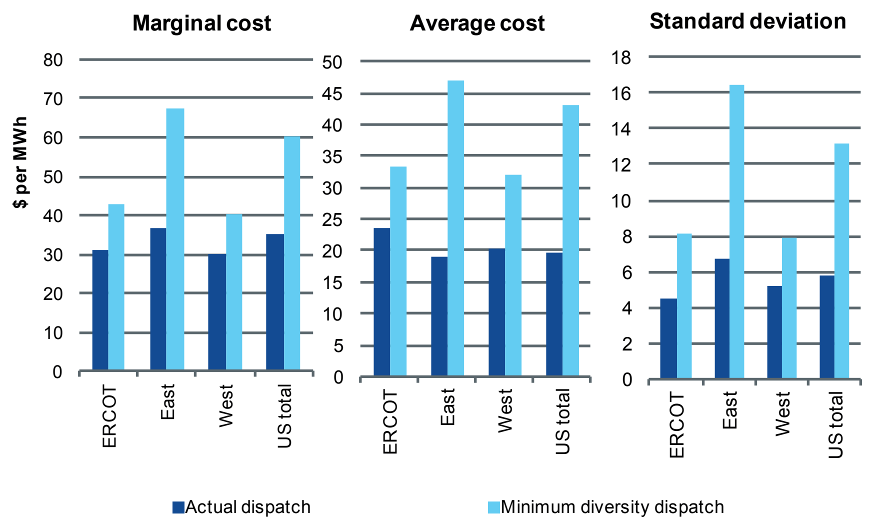
The value of the portfolio effect

The second step quantifies the portfolio value of the current generation mix. To measure this, the base case is altered by replacing the actual current generation mix with the less diverse generation mix. All else is held constant in this reduced diversity case, including the actual monthly fuel prices. Therefore, this reduced diversity simulation reduces the portfolio effect of diverse generation and allows any economic generation substitution to take place utilizing this less diverse capacity mix.

Figure 23 shows the performance metrics for each interconnection and the United States as a whole in the less diverse portfolio case compared to the base case.

FIGURE 23

Actual dispatch versus minimum diversity dispatch: Cost results



Source: IHS Energy

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The portfolio effect reduces not only costs, but also the variation in costs. This translates into a reduction in the typical monthly variation in consumers' power bills of between 25% and 30%.

The differences in average power production costs between the reduced diversity case and the current supply case indicate that fuel and technology diversity in the base case US generation mix provides power consumers with benefits of $93 billion per year. This difference between the reduced diversity case and the base case includes both the substitution and portfolio effects. Using the results of step one allows separation of these two effects, as shown in Table 4.

Figures 24 and 25 show the progression from the base case to the reduced diversity case. The results indicate that the Eastern power interconnection has the most to lose from a less diverse power supply because it faces more significant increases in cost, price, and variability in moving from the base case to the reduced diversity case. The Eastern interconnection ends up with greater variation in part because its delivered fuel costs are more varied than in Texas or the West. In addition, the natural endowments of hydroelectric power in the Western interconnection generation mix continue to mitigate some of the fuel price risk even at a reduced generation share.

In the past three years, generation supply diversity reduced US power supply costs by $93 billion per year, with the majority of the benefit coming from the portfolio effect. These estimates are conservative because they were made only across the recent past, 2010 to 2012. An evaluation over a longer period of history would show increased benefits from managing greater levels of fuel price risk.

The estimates of the current value of power supply diversity are conservative as well because they do not include the feedback effects of higher power cost variation on the cost of capital for power suppliers, as outlined in Appendix A. The analyses indicate that a power supplier with the production cost variation equal to the current US average would have a cost of capital 310 basis points lower than a power supplier

TABLE 4

Diversity cases cost results

		Substitution effect	Portfolio effect	Total
ERCOT	Output (2011, TWh)	334	334	334
	Marginal cost increase ($/MWh)	$11.10	$0.35	$11.45
	Average cost increase ($/MWh)	($0.91)	$10.62	$9.71
	Marginal cost increase split	97%	3%	100%
	Average cost increase split	-9%	109%	100%
	Marginal cost increase percentage	35.40%	1.10%	36.50%
	Average cost increase percentage	-3.90%	45.20%	41.40%
	Marginal cost increase (total)	$3,708,970,847	$116,702,120	$3,825,672,967
	Average cost increase (total)	($302,604,000)	$3,547,080,000	$3,244,476,000
Eastern interconnection	Output (2011, TWh)	2,916	2,916	2,916
	Marginal cost increase ($/MWh)	$26.01	$4.73	$30.74
	Average cost increase ($/MWh)	$1.10	$26.92	$28.02
	Marginal cost increase split	85%	15%	100%
	Average cost increase split	4%	96%	100%
	Marginal cost increase percentage	70.70%	12.80%	83.50%
	Average cost increase percentage	5.80%	142.70%	148.50%
	Marginal cost increase (total)	$75,840,639,098	$13,791,489,884	$89,632,128,981
	Average cost increase (total)	$3,207,600,000	$78,498,720,000	$81,706,320,000
Western interconnection	Output (2011, TWh)	728	728	728
	Marginal cost increase ($/MWh)	$4.94	$5.27	$10.21
	Average cost increase ($/MWh)	($0.10)	$11.67	$11.57
	Marginal cost increase split	48%	52%	100%
	Average cost increase split	-1%	101%	100%
	Marginal cost increase percentage	16.50%	17.60%	34.10%
	Average cost increase percentage	-0.50%	57.50%	57.00%
	Marginal cost increase (total)	$3,593,597,137	$3,837,638,788	$7,431,235,926
	Average cost increase (total)	($72,800,000)	$8,495,760,000	$8,422,960,000
US total	Output (2011, TWh)	3,978	3,978	3,978
	Marginal cost increase ($/MWh)	$20.90	$4.46	$25.36
	Average cost increase ($/MWh)	$0.71	$22.76	$23.47
	Marginal cost increase split	82%	18%	100%
	Average cost increase split	3%	97%	100%
	Marginal cost increase percentage	59.50%	12.70%	72.20%
	Average cost increase percentage	3.60%	116.70%	120.30%
	Marginal cost increase (total)	$83,143,207,082	$17,745,830,792	$100,889,037,874
	Average cost increase (total)	$2,832,196,000	$90,541,560,000	$93,373,756,000

Source: IHS Energy

with the production cost variation associated with the generation mix of the reduced diversity case. Since 14% of total power costs are returned to capital, this difference accounts for 1–3% of the overall cost of electricity. This cost-of-capital effect can have a magnified impact on overall costs if more capital has to be deployed with an acceleration of power plant closures and replacements from the pace that reflects underlying economics.

The cost of accelerating change in the generation mix

Current trends in public policies and flawed power market outcomes can trigger power plant retirements before the end of a power plant's economic life. When this happens, the closure creates cost impacts beyond the level and volatility of power production costs because it requires shifting capital away from a productive alternative use and toward a replacement power plant investment.

All existing power plants are economic to close and replace at some point in the future. The economic life of a power plant ends when the expected costs of continued operation exceed the cost of replacement. When this happens, the most cost-effective replacement power resource depends on the current capacity mix and what type of addition creates the greatest overall benefit—including the impact on the total cost of power and the management of power production cost risk.

Figure 26 shows the current distribution of the net present value (NPV) of the going-forward costs for the existing US coal-fired generation fleet on a cents per MWh basis in relation to the levelized NPV of replacement power on a per MWh basis.

As the distribution of coal-fired power plant going-forward costs indicates, there is a significant difference between the going-forward costs and the replacement costs for the majority of plants. As a result, a substantial cost exists to accelerate the turnover of coal-fired power plants in the capacity mix. For example, closing coal-fired power plants and replacing them as quickly as possible with natural gas–fired power plants would impose a turnover cost of around $500 billion.

FIGURE 24

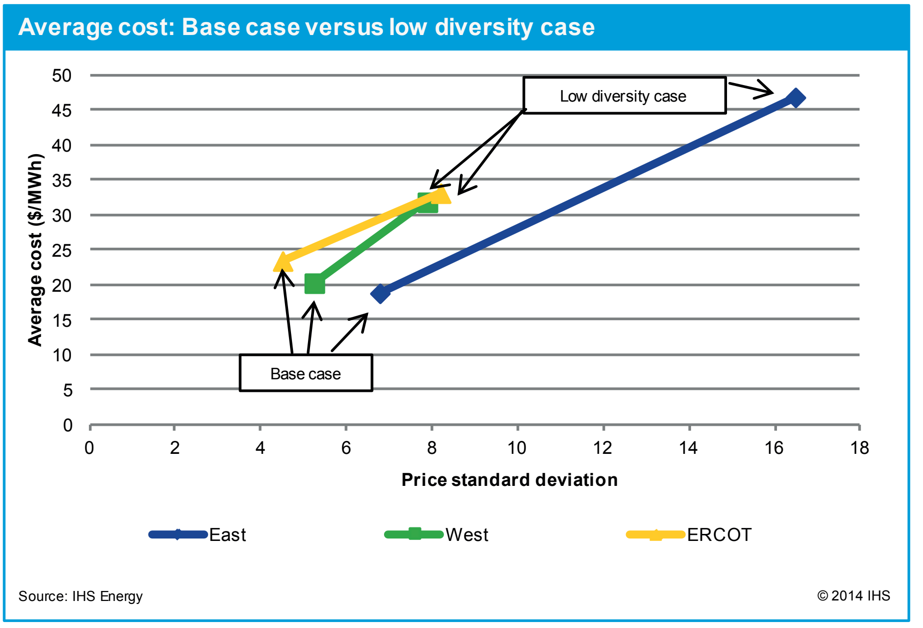


FIGURE 25

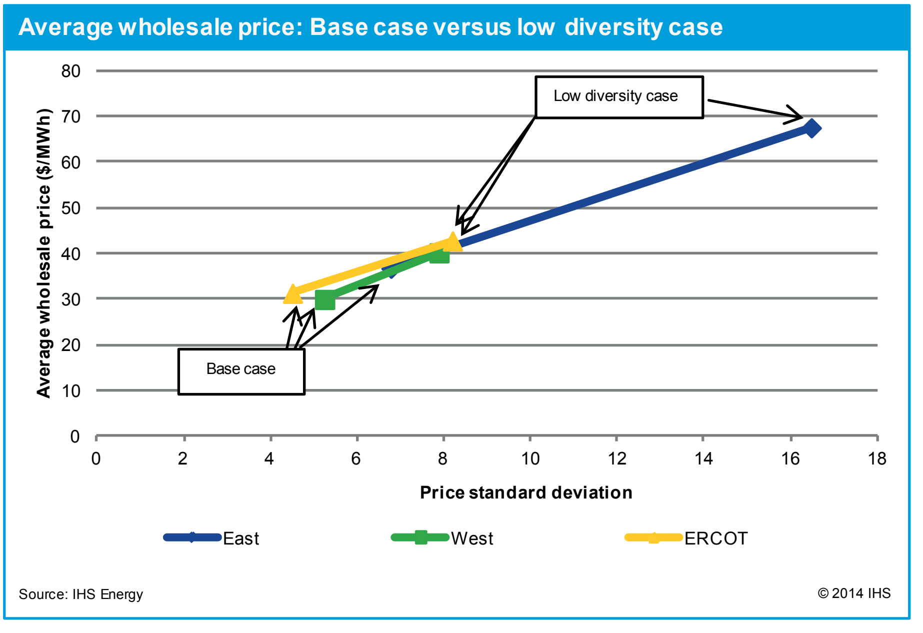
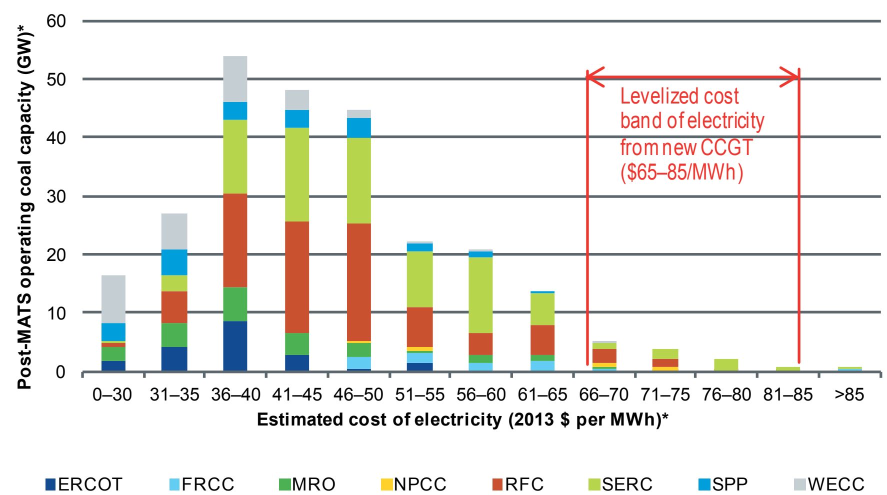


Figure 27 shows the going-forward costs of the existing US nuclear power plant fleet. As with the coal units, there is currently a high cost associated with premature closure. As a point of comparison, closing all existing nuclear power plants and replacing them as quickly as possible with natural gas–fired power plants would impose a turnover cost of around $230 billion. Unlike the coal fleet, where a nominal amount of older capacity has a going-forward cost that exceeds the expected levelized cost of replacement, none of the US nuclear capacity is currently more expensive than the lowest of projected replacement costs.

Closing a power plant and replacing it before its time means incurring additional capital costs. The average depreciation rate of capital in the United States is 8.3%. This implies that the average economic life of a capital investment in the United States economy is 12 years. Altering the amount of capital deployed in the US economy by $1 in Year 1 results in an equivalent impact on GDP as deploying a steady stream of about $0.15 of capital for each of the 12 years of economic life. This annual levelized cost approximates the value of the marginal product of capital. Therefore, each dollar of capital deployed to replace a power plant that retires prematurely imposes an opportunity cost equal to the value of the marginal productivity of capital in each year.

FIGURE 26

Going-forward costs of the existing coal fleet

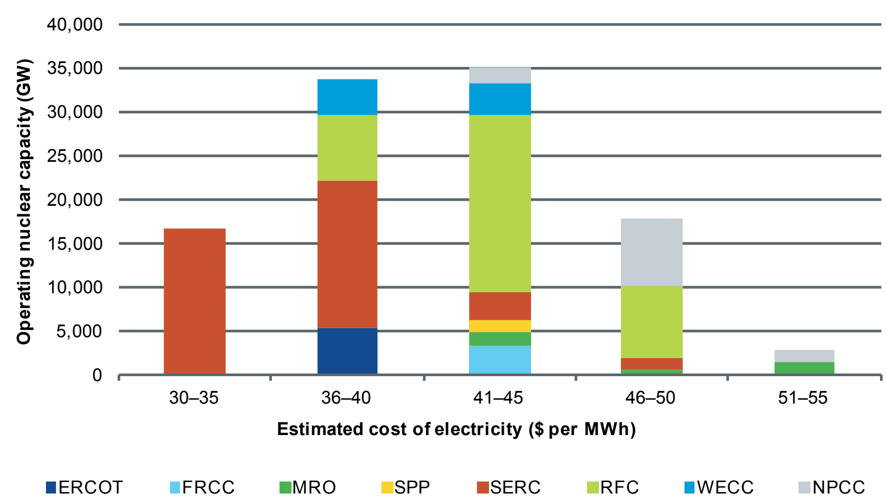


*Only includes those coal units that are forecasted to operate beyond 2020 in our reference case scenario. These coal units are retrofitted with conventional pollution controls.
Source: IHS Energy

Economywide impacts

FIGURE 27

Going-forward costs of the existing nuclear fleet



Source: IHS Energy

In addition to the $93 billion in lost savings from the portfolio and substitution effects, depending upon the pace of premature closures, there is a cost to the economy of diverting capital from other productive uses. The power price increases associated with the reduced diversity case would profoundly affect the US economy. The reduced diversity case shows a 75% increase in average wholesale power prices compared to the base case. IHS Economics conducted simulations using its US Macroeconomic Model to assess the potential impact of the change in the level and variance of power prices between the base case and the reduced diversity case. The latest IHS base line macroeconomic outlook in December 2013 provides a basis for evaluating the impacts of an electricity price shock due to a reduced diversity case for power supply. Subjecting the current US economy to such a power price increase would trigger economic disruptions, some lasting over a multiyear time frame. As a result, it would take several years for most of these disruptions to dissipate. To capture most of these effects, power price changes were evaluated over the period spanning the past two and the next three years to approximate effects of a power price change to the current state of the economy. Wholesale power price increases were modeled by increasing the

Producer Price Index for electricity by 75% in the macroeconometric model; consumers were affected by the resulting higher prices for retail electricity and other goods and services.

Economic impacts of the power supply reduced diversity case are quantified as deviations from the IHS macroeconomic baseline simulations of the US economy. The major impacts within the three years after the power price change would include

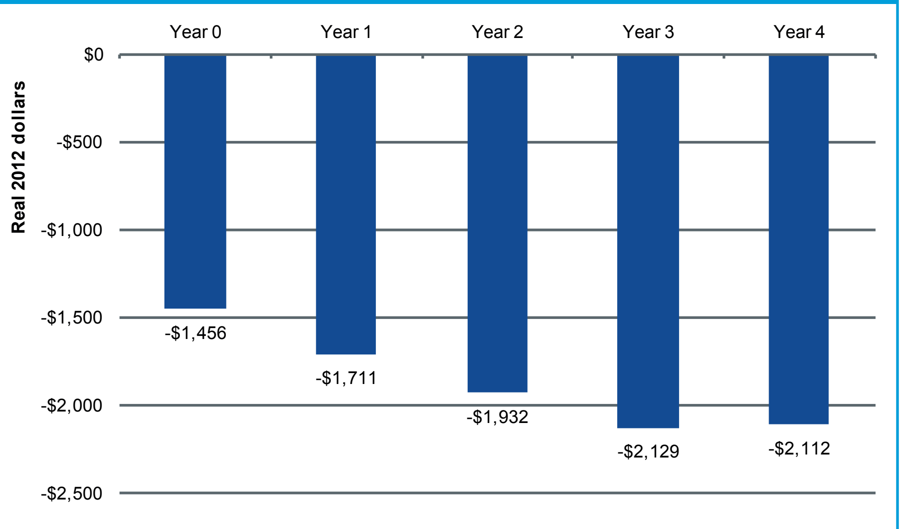
- A drop in real disposable income per household of about $2,100
- A reduction of 1,100,000 jobs
- A decline in real GDP of 1.2%

Consumers will bear the brunt of the impact of higher power prices. The higher price of electricity would trigger a reduction in power use in the longer run (10 or more years out) of around 10%. Yet even with such dramatic reductions in consumption, the typical power bill in the United States would increase from around $65 to $72 per month.

Not only will consumers face higher electric bills, but some portion of increases in manufacturers' costs ultimately will be passed on to consumers through higher prices for goods and services. Faced with lower purchasing power, consumers will scale back on discretionary purchases because expected real disposable income per household is lower by over $2,100 three years after the electric price increase (see Figure 28). Unlike other economic indicators (such as real GDP) that converge toward equilibrium after a few years, real disposable income per household does not recover, even if the simulations are extended out 25 years. This indicates that the price increases will have a longer-term negative effect on disposable income and power consumption levels.

FIGURE 28

Impact of reduced diversity on real disposable income



Source: IHS Economics © 2014 IHS

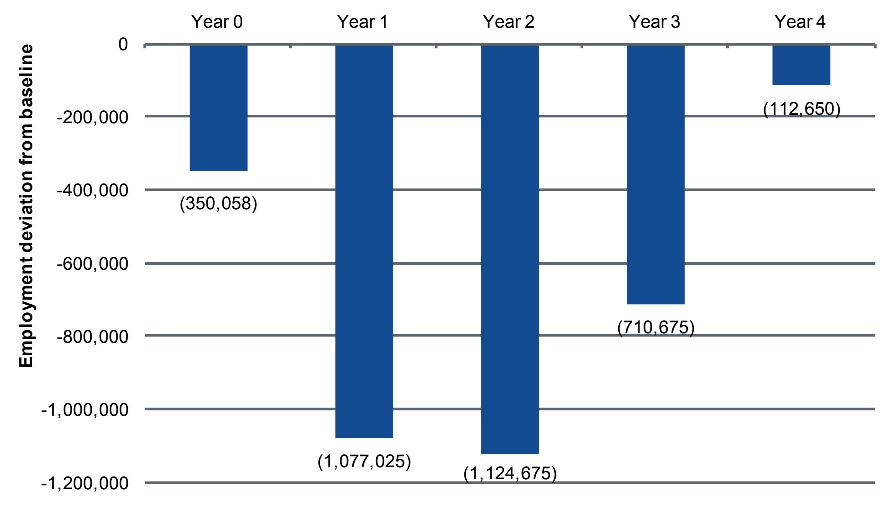
Businesses will face the dual challenge of higher operational costs coupled with decreased demand for their products and services. Industrial production will decline, on average, by about 1% through Year 4. This will lead to fewer jobs (i.e., a combination of current jobs that are eliminated and future jobs that are never created) within a couple of years relative to the IHS baseline forecast, as shown in Figure 29, with the largest impact appearing in Year 2, with 1,100,000 fewer jobs than the IHS baseline level.

Impact on GDP

The US economy is a complex adaptive system that seeks to absorb shocks (e.g., increases in prices) and converge toward a long-term state of equilibrium. Although the simulations conducted for this study do not project that the US economy will fall into a recession because of power price increases, it is informative to gauge the underperformance of the US economy under the reduced diversity case. In essence, the higher power prices resulting from the reduced diversity conditions cause negative economic impacts equivalent to a mild recession relative to the forgone potential GDP of the baseline. The economic impacts of the reduced diversity case set back GDP by $198 billion, or 1.2% in Year 1 (see Figure 30). This deviation from the baseline GDP is a drop that is equivalent to about half of the average decline in GDP in US recessions since the Great Depression. However, the impacts on key components of GDP such as personal consumption and business investment will differ.

FIGURE 29

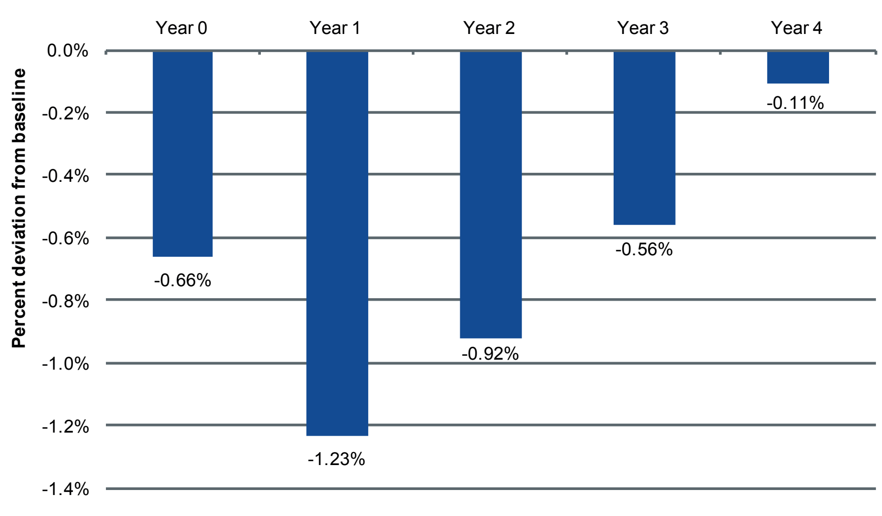
Impact of reduced diversity on employment (deviation from baseline)



Source: IHS Economics © 2014 IHS

FIGURE 30

Impact of reduced diversity on real GDP



Source: IHS Economics © 2014 IHS

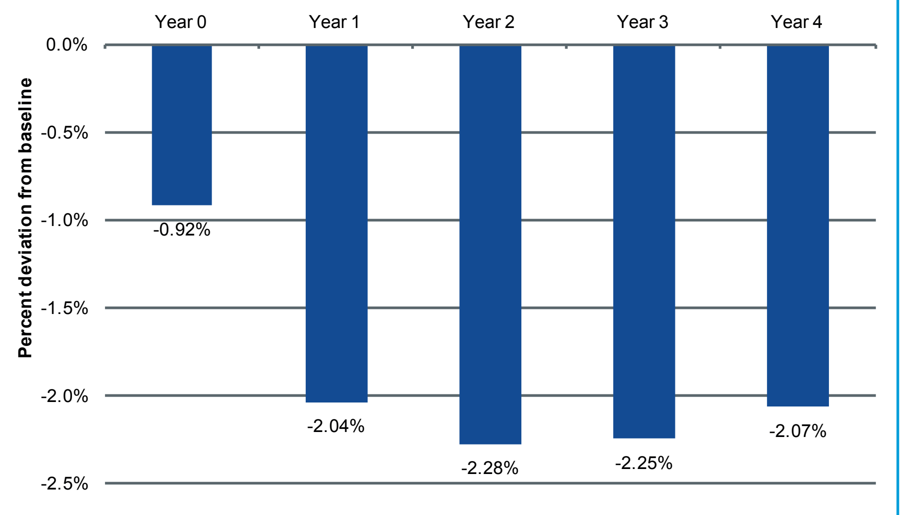
Consumption

Analyzing personal consumption provides insights on the changes to consumer purchasing behavior under the scenario conditions. Consumption, which accounts for approximately two-thirds of US GDP, remains lower over the period with each of its three subcomponents—durable goods, nondurable goods, and services—displaying a different response to the reduced power supply scenario conditions. In contrast with overall GDP, consumer spending shows little recovery by Year 4, as shown in Figure 31. This is due to continued higher prices for goods and services and decreased household disposable income. About 57% of the decline will occur in purchases of services, where household operations including spending on electricity will have a significant impact.

In the early years, lower spending on durable goods (appliances, furniture, consumer electronics, etc.) will account for about 33% of the decline, before moderating to 25% in the longer term. This indicates that consumers, faced with less disposable income, will simply delay purchases in the early years. The US macro simulations also predict moderate delays in housing starts and light vehicle sales, ostensibly due to consumers trying to minimize their spending.

FIGURE 31

Impact of reduced diversity on consumption



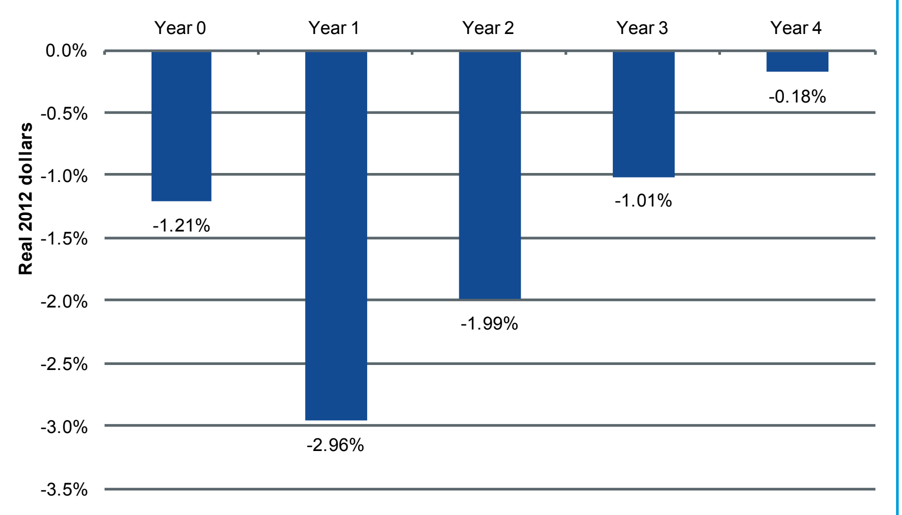
Source: IHS Energy © 2014 IHS

Investment

Following an initial setback relative to the baseline, investment will recover by the end of the forecast horizon. Nonresidential investment will initially be characterized by delays in equipment and software purchases, which will moderate a few years after the electric price shock. Spending on residential structures will remain negative relative to the baseline over the four years, as shown in Figure 32. The net effect in overall investment is a recovery as the economy rebounds back to a long-run equilibrium.

FIGURE 32

Impact of reduced diversity on investment



Source: IHS Energy © 2014 IHS

In the longer term, if current trends cause the reduced diversity case to materialize within the next decade, then the premature closure and replacement of existing power plants would shift billions of dollars of capital from alternative deployments in the US economy.

Conclusions

Consumers want a cost-effective generation mix. Obtaining one on the regulated and public power side of the industry involves employing an integrated resource planning process that properly incorporates cost-effective risk management. Obtaining such a mix on the competitive side of the power business involves employing time-differentiated market-clearing prices for energy and capacity commodities that can provide efficient economic signals. The linkage between risk and cost of capital can internalize cost-effective risk management into competitive power business strategies. Regardless of industry structure, a diverse generation mix is the desired outcome of cost-effective power system planning and operation.

The results of this study indicate seven key factors that will shape US power supply diversity in the years to come:

- **Energy policy development.** US policy heavily influences the US power supply mix. Implementing an all-of-the-above energy policy requires properly internalizing the value of fuel diversity.

- **Market structure.** Market flaws distort wholesale power prices downward and result in uneconomic retirement and replacement of existing cost-effective generation resources. This issue and any market structure changes to address it will significantly shape future power plant development.

- **Energy policy discourse.** Preserving the value of fuel diversity depends on public awareness and understanding. The extent and nature of public education regarding the value of power supply diversity may strongly influence public opinion.

- **Planning alignment.** Alignment of fuel and technology choices for power generation with engineering and economic principles is critical to efficient and reliable supply. There is no single fuel or technology of choice for power generation, and all forms of power production have economic, environmental, and reliability impacts.

- **Risk assessment.** To incorporate system considerations into plant-level decisions, prudent fuel price uncertainties must be used with probabilistic approaches to decision making.

- **Flexibility.** Flexibility and exemptions in rule making and implementation allow for the balancing of costs and benefits in power supply systems and may help preserve highly valuable diversity in systemwide decisions as well as on a small but impactful individual plant scale.

- **Scope.** Including fuel price risk and additional storage and transportation infrastructure costs is crucial when evaluating reduced diversity scenarios in comparison to the cost of maintaining and expanding fuel diversity.

Appendix A: Cost-effective electric generating mix

The objective of power supply is to provide reliable, efficient, and environmentally responsible electric production to meet the aggregate power needs of consumers at various points in time. Consumers determine how much electricity they want at any point in time, and since the power grid physically connects consumers, it aggregates individual consumer demands into a power system demand pattern that varies considerably from hour to hour. For example, Figure A-1 shows the hourly aggregate demand for electricity in ERCOT.

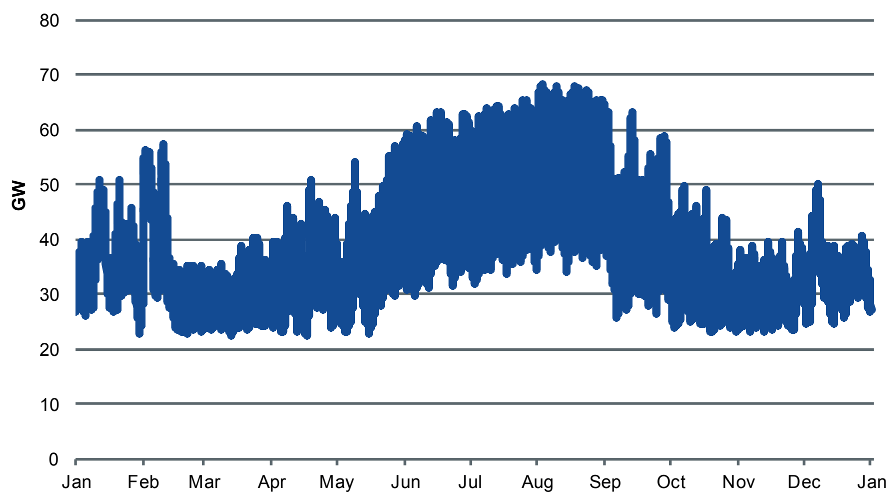
In order to reliably meet aggregate power demands, enough generating capacity needs to be installed and available to meet demand at any point in time. The overall need for installed capacity is determined by the peak demand and a desired reserve margin. A 15% reserve margin is a typical planning target to insure reliable power supply.

The chronological hourly power demands plus the required reserve margin allow the construction of a unitized load duration curve (see Figure A-2). The unitized load duration curve orders hourly electric demands from highest to lowest and unitizes the hourly loads by expressing the values on the y-axis as a percentage of the maximum (peak) demand plus the desired reserve margin. The x-axis shows the percentage of the year that load is at or above the declining levels of aggregate demand.

This unitized load duration curve has a load factor—the ratio of average load to peak load—of 0.60. Although load duration curve shapes vary from one power system to another, this load factor and unitized load duration curve shape is a reasonable approximation of a typical pattern of electric

FIGURE A-1

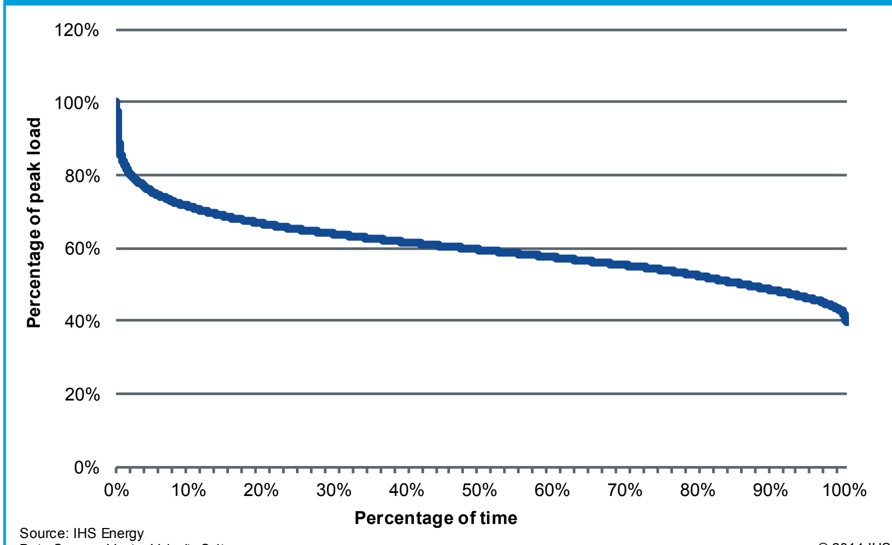
2011 hourly electric loads—ERCOT



Source: IHS Energy © 2014 IHS

FIGURE A-2

Load duration curve



Source: IHS Energy
Data Source: Ventyx Velocity Suite
© 2014 IHS

demand in a US power system. The objective of any power system would be to match its demand pattern with cost-effective power supply.

There are a number of alternative technologies available to produce electricity. These power supply alternatives have different operating characteristics. Most importantly, some power generating technologies can produce electricity on demand that aligns with the pattern of consumer demand through time, while others cannot. For example, solar PV panels can only provide electric output during hours of sunlight and thus cannot meet aggregate demand during the night. In contrast, thermal generation such as coal and natural gas can ramp up and down or turn on and off to match output with customer demand. Technologies such as coal and natural gas are considered dispatchable, while technologies such as solar and wind are considered nondispatchable. A number of combinations of technologies can together provide electric output that matches the pattern of consumer needs.

The lowest-cost generating technologies that can meet the highest increases in demand are peaking technologies such as combustion turbines (CTs). CTs are the most economical technology to meet loads that occur for only a small amount of time. These technologies can start-up quickly and change output flexibly to meet the relatively infrequent hours of highest power demand. They are economic even though they are not the best available technology for efficiently transforming fuel into electricity. CTs have relatively low upfront capital costs and thus present a trade-off with more efficient but higher capital cost generating technology alternatives. Since these resources are expected to be used so infrequently, the additional cost of more efficient power generation is not justified by fuel savings, given their expected low utilization rates.

Cycling technologies are most economical to follow changes in power demand across most hours. Consequently, utilization rates can be high enough to generate enough fuel savings to cover the additional capital cost of these technologies over a peaking technology. These intermediate technologies provide flexible operation along with efficient conversion of fuel into power. A natural gas–fired combined-cycle gas turbine (CCGT) is one technology that is suitable and frequently used for this role.

Base-load technologies are the lowest-cost power supply sources to meet power demand across most hours. These technologies are cost-effective because they allow the trading of some flexibility in varying output for the lower operating costs associated with high utilization rates. These technologies include nuclear power plants, coal-fired power plants, and reservoir hydroelectric power supply resources.

Nondispatchable power resources include technologies such as run-of-the-river hydroelectric, wind, and solar power supplies. These technologies produce power when external conditions allow—river flows, wind speeds, and solar insolation levels. Variations in electric output from these resources reflect changes in these external conditions rather than changes initiated by the generator or system operator to follow shifts in power consumer needs. Some of these resources can be economic in a generation mix if the value of the fuel they displace and their net dependable capacity are enough to cover their total cost. However, since nondispatchable production profiles do not align with changes in consumer demands, there are limits to how much of these resources can be cost-effectively incorporated into a power supply mix.

Alternative power generating technologies also have different operating costs. Typical cost profiles for alternative power technologies are shown in Table A-1. Both nuclear and supercritical pulverized coal (SCPC) technologies are based on steam turbines, whereby superheated steam spins a turbine; in coal's case, supercritical refers to the high-pressure phase of steam where heat transfer and therefore the turbine itself is most efficient. Natural gas CTs are akin to jet engines, where the burning fuel's exhaust spins the turbine. A CCGT combines both of these technologies, first spinning a CT with exhaust and then using that exhaust to create steam which spins a second turbine.

TABLE A-1

Typical cost profiles for alternative power technologies

	CCGT	SCPC	Nuclear	CT
Capital cost (US$ per kW)	1,350	3,480	7,130	790
Variable O&M cost (US$ per MWh)	3.5	4.7	1.6	4.8
First year fixed O&M cost (US$ per kW-yr)	13	39	107	9
Property tax and insurance (US$ per kW-yr)	13	36	78	8
Fuel price (US$ per MMBtu)	4.55	2.6	0.7	4.55
Heat rate (Btu per kWh)	6,750	8,300	9,800	10,000
CO_2 emission rate (lbs per kWh)	0.8	1.73	0	1.18

Total capital cost figures include owner's costs: development/permitting, land acquisition, construction general and administrative, financing, interest during construction, etc.

Source: IHS Energy

Power production technologies tend to be capital intensive; the cost of capital is an important determinant of overall costs. The cost of capital is made up of two components: a risk-free rate of return and a risk premium. Short-term US government bond interest rates are considered an approximation of the risk-free cost of capital. Currently, short-term US government bond interest rates are running at 0.1%. In order to attract capital to more risky investments, the return to capital needs to be greater. For example, the average cost of new debt to the US investor-owned power industry is around 4.5%.[11] This indicates an average risk premium of 4.4%.

Power generating technologies have different risk profiles. For example, the fluctuations in natural gas prices and demand levels create uncertainty in plant utilization and the level of operating costs and revenues. This makes future net income uncertain. Greater variation in net income makes the risk of covering debt obligations greater. In addition, more uncertain operating cost profiles add costs by imposing higher working capital requirements.

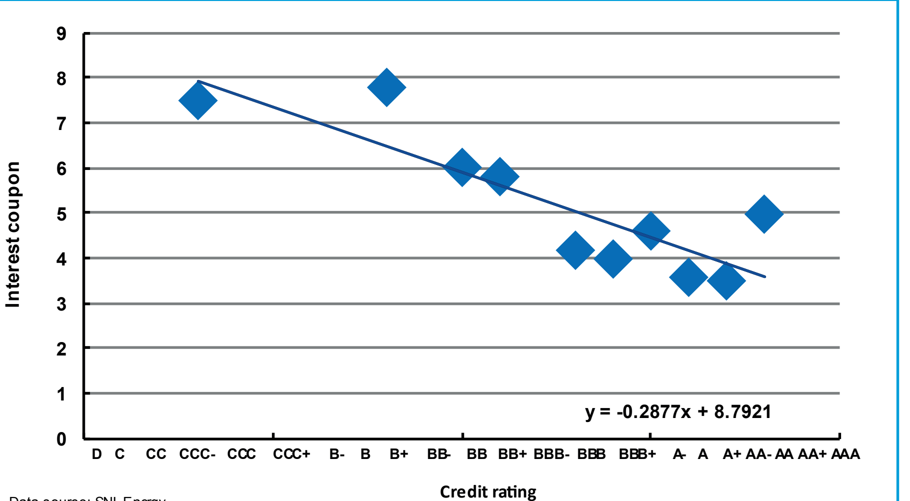
Risk profiles are important because they affect the cost of capital for power generation projects. If a project is seen as more risky, investors demand a higher return for their investment in the project, which can have a significant impact on the overall project cost.

Credit agencies provide risk assessments and credit ratings to reflect these differences. Credit ratings reflect the perceived risk of earning a return on, and a return of, capital deployments. As Figure A-3 shows, the higher credit ratings associated with less risky investments have a lower risk premium, and conversely lower credit ratings associated with more risky investments have a higher risk premium.

Lower credit ratings result from higher variations in net

FIGURE A-3

2010 shareholder-owned utilities senior debt offerings average interest coupon versus credit rating



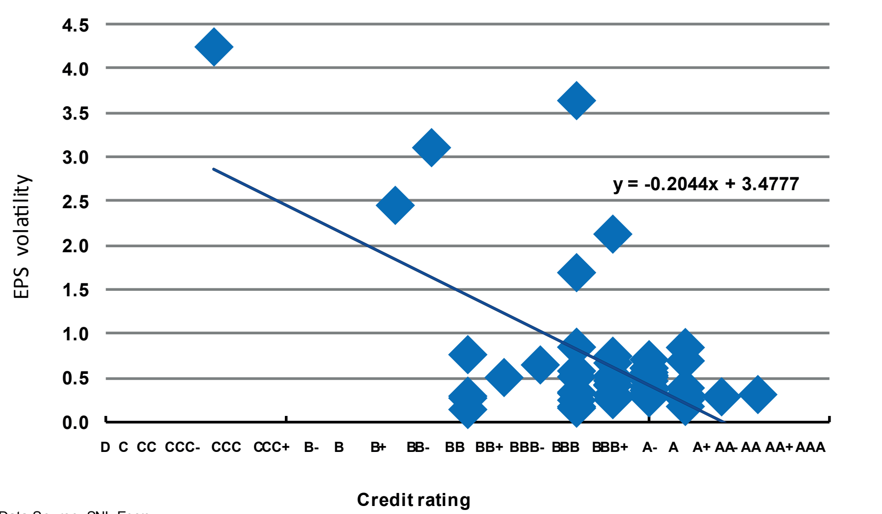
Data source: SNL Energy.
Source: IHS Energy
© 2014 IHS

11. Data collected by Stern School of Business, NYU, January 2014. Cost of Capital. Accessed at http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/wacc.htm.

income, as shown in Figure A-4.

FIGURE A-4

Earnings per share volatility versus credit ratings



Data Source: SNL Energy
Notes: EPS = earnings per share.
Volatility is measured by standard deviation.
Source: IHS Energy © 2014 IHS

Sometimes the cost of capital is directly related to the power plant when project financing is used. In other cases, power companies raise capital at the corporate level with a capital cost that reflects the overall company risk profile rather than just the power plant risk profile. Utilities typically have diverse power supply portfolios, whereas merchant generators tend to be much less diverse—typically almost entirely natural gas-fired. As a result of the different supply mixes and associated risk profiles, utilities and merchant generators have different costs of capital. This difference in the cost of capital provides an approximation of the difference in risk premium.

Overall, the cost of capital for merchant generators is higher than that for utilities broadly. While the power industry has an average cost of debt of roughly 4.5%, merchant generators with significant natural gas holdings tend to have a cost of debt of around 8%. As many of these firms have gone through bankruptcies in the past, this number may be lower than the cost of debt these firms had prior to restructuring.[12] The implied risk premium of a merchant generator to a utility is 3.5%, which is similar to the cost of capital analysis results discussed in the body of the report, where the reduced diversity case generator was calculated to have a cost of capital 310 basis points (3.1%) higher than that of the current US power sector as a whole.

Merchant generators with majority natural gas holdings have higher costs of capital because of the increased earnings volatility and risk of an all natural gas portfolio. In contrast, a generator with a more diverse portfolio needing to secure financing for the same type of plant would have costs of capital more in line with the industry as a whole. This can have a significant impact on the overall cost of the plant. This is not due specifically to the properties of natural gas as a fuel, but rather to the diversity of generating resources available. If a merchant generator were to have an exclusively coal-fired generating fleet or an exclusively nuclear generating fleet, its cost of capital would also increase owing to the higher uncertainty in generation cash flows.

The expected annual power supply costs can be calculated over the expected life of a power plant once the cost of capital is set and combined with the cost and operating profile data. These power costs are uneven through time for a given utilization rate. Therefore, an uneven cost stream can be expressed as a levelized cost by finding a constant cost in each year that has the same present value as the uneven cost stream. The discount rate used to determine this present value is based on the typical cost of capital for the power

12. Based on analysis of the "Competitive" business strategy group, defined by IHS as businesses with generation portfolios that are over 70% nonutility, based on asset value and revenue. Cost of debt based on coupon rates of outstanding debt as of May 2014.

industry as a whole. Dividing the levelized cost by the output of the power plant at a given utilization rate produces a levelized cost of energy (LCOE) for a given technology at a given utilization rate (see Figure A-5).

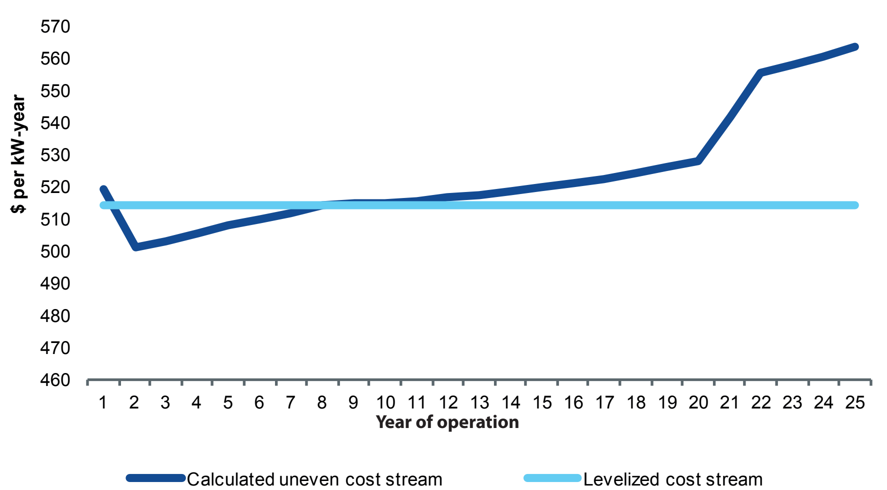
A levelized cost stream makes it possible to compare production costs at different expected utilization rates. A lower utilization rate forces spreading fixed costs over fewer units of output and thus produces higher levelized costs (see Figure A-6).

Figure A-7 adds the LCOE of a CT. Since the LCOE of the CT is lower than that of the CCGT at high utilization rates, adding CTs shows the point at which the savings for a CCGT's greater efficiency in fuel use are enough to offset the lower fixed costs of a CT.

There is a utilization rate at which a CCGT is cheaper to run than a CT. Below a utilization rate of roughly 35%, a CT is more economical. At higher utilization rates, the CCGT is more economical. When referring back to the load duration curve, it can be calculated that a generation mix that is 37% CT and 63% CCGT would produce a least-cost outcome. This can be demonstrated by comparing the LCOE graph with the load duration curve: the intersection point of CT and CCGT LCOEs occurs at the same time percentage on the LCOE graph at which 63% load occurs on the load duration curve (see Figure A-8).

FIGURE A-5

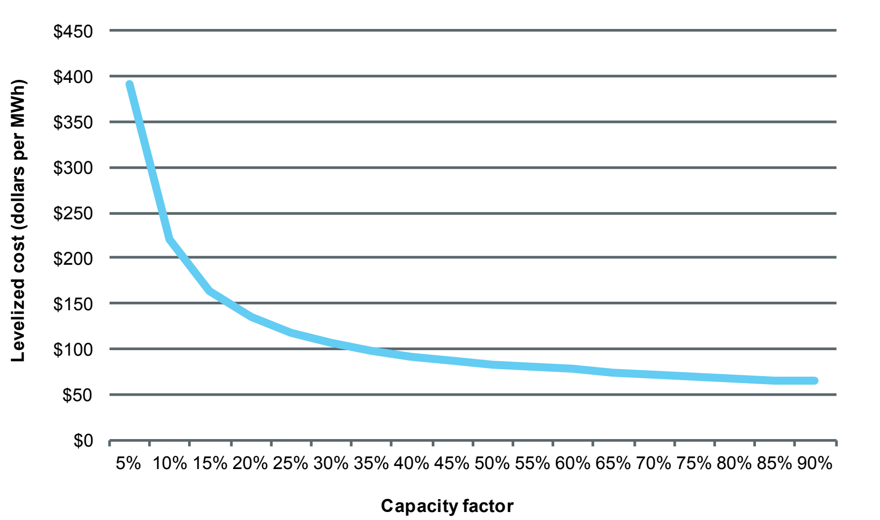
Cost stream comparisons—CCGT, 85% utilization rate



Source: IHS Energy © 2014 IHS

FIGURE A-6

LCOE of CCGT generation



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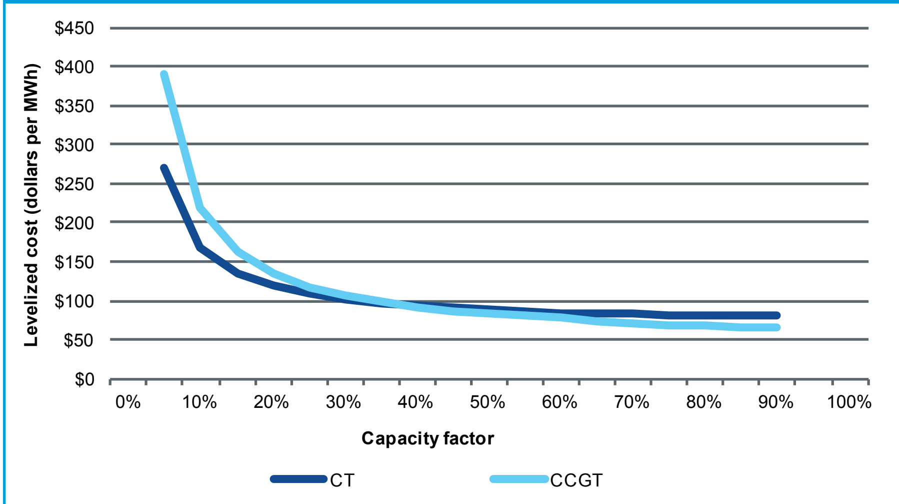
The levelized cost of production for each technology can be determined by finding the average load (and corresponding utilization rate) for the segment of the load duration curve (LDC) that corresponds to each technology (in this example, the two segments that are created by splitting the curve at the 35% mark). Loads that occur less than 35% of the time will be considered peak loads, so the average cost of meeting a peak load will be equivalent to the cost of a CT operating at a 17.5% utilization rate, the average of the peak loads. Cycling loads will be defined as loads occurring between 35% to 80% of the time, with base loads occurring more than 80% of the time. As the CCGT is covering both cycling and base loads in this example, the average cost of meeting theses loads with a CCGT will be equivalent to the levelized cost of a CCGT at a 57.5% utilization rate. A weighted average of the costs of each technology is then equivalent to an average cost of production for the power system. For this generation mix, the levelized cost of production is equal to 9.6 cents per kWh.

FIGURE A-7

LCOE of CCGT and CT generation



Source: IHS Energy

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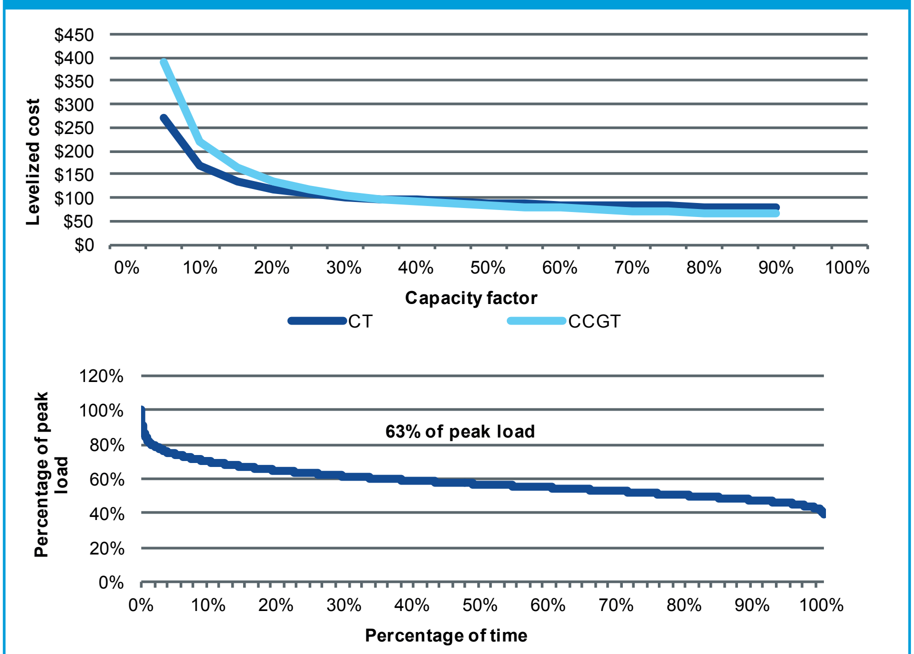
FIGURE A-8

Determination of generation mix based on load duration curve



Source: IHS Energy
Data Source: Ventyx Velocity Suite, National Renewable Energy Laboratory

Source:

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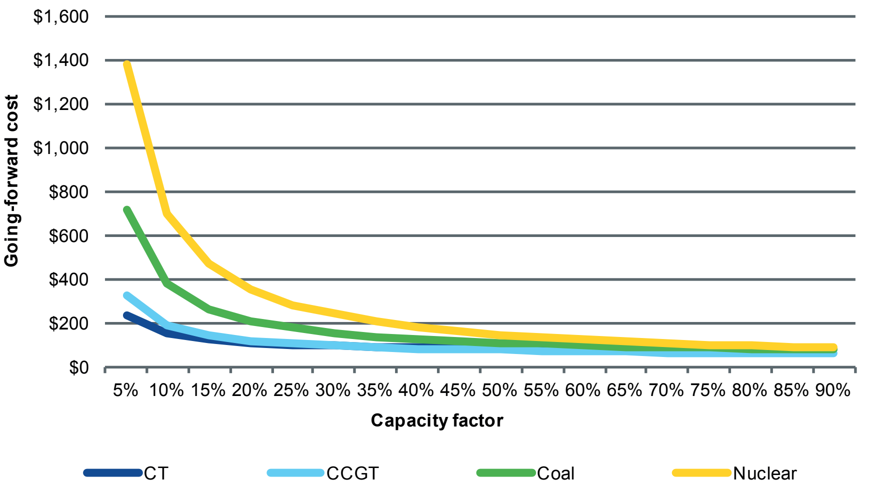
The generating options also can be expanded to include fuels besides natural gas. Stand-alone coal and stand-alone nuclear are not lower cost than stand-alone gas, as shown in Figure A-9, and all have a high-risk premium associated with the lack of diversity. However, when combined as part of a generation mix, the cost of capital will be lower owing to the more diverse (and therefore less risky) expected cash flow.

Based on the LDC, in this example base-load generation was modeled at 52.5% of capacity and was composed of equal parts gas, coal, and nuclear capacity. This combination of fuels and technology produces a diverse portfolio that can reduce risk and measurably lower the risk premium in the cost of capital. The point at which a CCGT becomes cheaper than a CT changes slightly from the previous example owing to the change in cost of capital, but the result is similar, with a 30% utilization rate the critical point and 36% CT capacity the most economical. Cycling loads with utilization rates between 30% and 80% can be covered by CCGTs, equaling 11.5% of capacity. The levelized cost of production for this more diverse portfolio is equal to 9.3 cents per kWh. Even though coal and nuclear have higher levelized costs than gas, all else being equal, the reduced cost of capital is more than enough to offset the increased costs of generation. The implication is that a least-cost mix to meet a pattern of demand is a diverse mix of fuels and technologies.

If the power system has a renewables mandate, this can be incorporated as well. Solar PV has a levelized cost of 14.2 cents per kWh, given a 4.5% cost of capital. If solar made up 10% of generating capacity, the load duration curve for the remaining dispatchable resources would change, as shown in Figure A-10. Using hourly solar irradiation data from a favorable location to determine solar output, the peak load of the power system does not change, as there is less than full solar insulation in the hour when demand peaks.[13] The load factor for this new curve is 0.58, a small decrease from the original curve. A lower load factor typically means that larger loads occur less often, so more peaking capacity is necessary.

FIGURE A-9

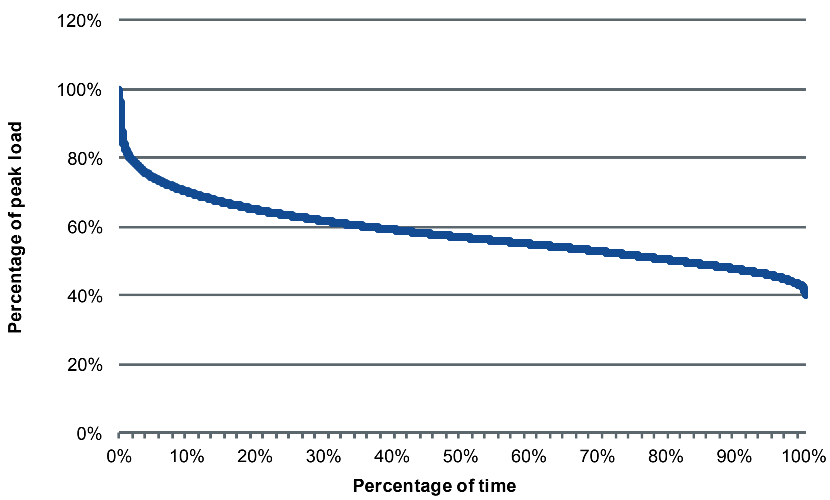
Levelized cost curves of generating resources



Source: IHS Energy © 2014 IHS

FIGURE A-10

Load duration curve, after solar additions



Source: IHS Energy
Data Source: Ventyx Velocity Suite, National Renewable Energy Laboratory © 2014 IHS

The needed dispatchable resources can be recalculated using the new curve, integrating the solar generation. The new curve increases the amount of peaking resources needed, but otherwise changes only very slightly. After solar is added, the total cost is 10.8 cents per kWh. Since the output pattern of solar doesn't match the demand pattern for the power system, adding solar does not significantly decrease the amount of capacity needed.

13. Solar data from National Renewable Energy Laboratory, Austin, TX, site. Data from 1991–2005 update, used for example purposes. http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/tmy3/by_state_and_city.html accessed 13 May 2014.

Conclusion

- There is no single fuel or technology of choice for power generation. Reliably and efficiently supplying consumers with the amounts of electricity that they want, when they want it, requires a diverse generation mix.

- A cost-effective generation mix involves diversity but does not involve maximizing diversity by equalizing generation shares from all available supply options.

- The cost-effective mix of fuel and technologies for any power system is sensitive to the uncertainties surrounding the level and pattern of consumer power demands as well as expectations regarding the cost and performance of alternative power generating technologies and, in particular, the expectations for delivered fuel prices.

- The cost-effective generating mix will differ from one power system to the next because of differences in aggregate consumer demand patterns as well as the cost and performance of available generating options.

- The best type of capacity to add to any generation portfolio depends on what types of capacity are already in the mix.

Appendix B: IHS Power System Razor Model overview

Design

The IHS Power System Razor (Razor) Model was developed to simulate the balancing of power system demand and supply. The model design provides flexibility to define analyses' frequency and resolution in line with available data and the analytical requirements of the research investigation.

For this assessment of the value of fuel diversity, the following analytical choices were selected:

- **Analysis time frame**—Backcasting 2010 to 2012
- **Analysis frequency**—Weekly balancing of demand and supply
- **Geographic scope**—US continental power interconnections—Western, Eastern, and ERCOT
- **Demand input data**—Estimates of weekly interconnection aggregate consumer energy demand plus losses
- **Fuel and technology types**—Five separate dispatchable supply alternatives: nuclear, coal steam, natural gas CCGT, gas CT, and oil CT
- **Supply input data by type**—Monthly installed capacity, monthly delivered fuel prices, monthly variable operations and maintenance (O&M), heat rate as a function of utilization
- **Load modifiers**—Wind, solar, hydroelectric, net interchange, peaking generation levels, and weekly patterns

Demand

The Razor Model enables the input of historical demand for backcasting analyses as well as the projection of demand for forward-looking scenarios. In both cases, the Razor Model evaluates demand in a region as a single aggregate power system load.

For backcasting analyses, the model relies upon estimates of actual demand by interconnection. For forward-looking simulations, Razor incorporates a US state-level cross-sectional, regression-based demand model for each of the three customer classes—residential, commercial, and industrial. Power system composite state indexes drive base year demand levels by customer class into the future.

Load modifiers

Utilization of some power supply resources is independent of SRMC–based dispatch dynamics. Some power supply is determined by out-of-merit-order utilization, normal production patterns, or external conditions—such as solar insolation levels, water flows, and wind patterns. These power supply resources are treated as load modifiers.

Net load

Net load is the difference between power system aggregate electric output needs and the aggregate supply from load modifiers. It is the amount of generation that must be supplied by dispatchable power supply resources.

Calibration of the inputs determining net load is possible using data reporting the aggregate output of dispatchable power sources.

Fuel- and technology-specific supply curves

Supply curves are constructed for each fuel and technology type. The supply curve for each dispatchable power supply type reflects the SRMCs of the capacity across the possible range of utilization rates. Applying availability factors to installed capacity produces estimates of net dependable (firm, derated) capacity by fuel and technology type.

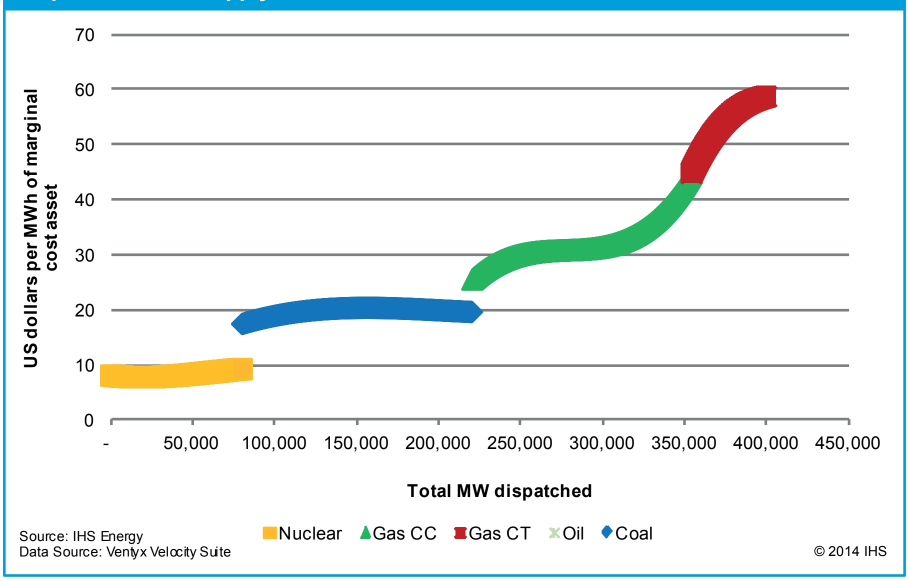
Each cost curve incorporates heat rate as a function of utilization rate.[14] *Heat rate* describes the efficiency of a thermal power plant in its conversion of fuel into electricity. Heat rate is measured by the amount of heat (in Btu) required each hour to produce 1 kWh of electricity, or most frequently shown as MMBtu per MWh. The higher the heat rate, the more fuel required to produce a given unit of electricity. This level of efficiency is determined primarily by the fuel type and plant design. Outliers are pruned from data to give a sample of heat rates most representative of the range of operational plants by fuel and technology type.[15]

Dispatch fuel costs are the product of the heat rate and the delivered fuel cost. Total dispatch costs involve adding variable operations and maintenance (VOM, or O&M) costs to the dispatch fuel costs. These O&M costs include environmental allowance costs.

The power system aggregate supply curve is the horizontal summation of the supply curves for all fuel and technology types. Figure B-1 illustrates the construction of the aggregate power system supply curve. The supply curve shows the SRMC at each megawatt dispatch level and the associated marginal resource.

FIGURE B-1

Representative supply curve



Balancing power system aggregate demand and supply

The Razor Model balances aggregate power system demand and supply by intersecting the demand and supply curves. At the intersection point, power supply equals demand; supply by type involves equilibrating the dispatch costs of available alternative sources of supply.

14. Power plant data sourced from Ventyx Velocity Suite.

15. Outliers are defined as plants with an average heat rate higher than the maximum observed fully loaded heat rate.

This power system–wide marginal cost of production is the basis for the wholesale power price level that clears an energy market.

The Razor Model results in the following outputs:

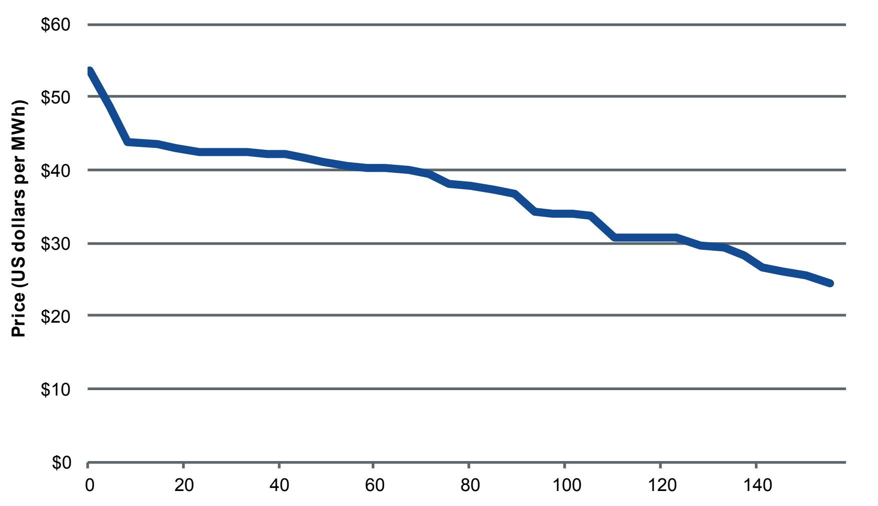
- **Power system SRMC/wholesale price**
- **Generation by fuel and technology type**
- **Average variable cost of production.** The average variable cost is calculated at each dispatch increment by taking the total cost at that generation level divided by the total megawatt dispatch.
- **Price duration curve.** The price duration curve illustrated in Figure B-2 provides an example of wholesale power price distribution across the weeks from 2010 through 2012.

Calibration

The predictive power of the Razor Model for portfolio and substitution analysis is revealed by comparing the estimated values of the backcasting simulations to the actual outcomes in 2010–12.

FIGURE B-2

Representative price duration curve



Source: IHS Energy
Data Source: Ventyx Velocity Suite
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The Razor Model backcasting results provide a comparison of the estimated and actual wholesale power prices. The average difference in the marginal cost varied between (3.8%) and +2.3% by interconnection region. A comparison of the average rather than marginal cost of power production also indicated a close correspondence. The average difference between the estimate and the actual average cost of power production varied between (4.7%) and (0.1%) by interconnection region. Table B-1 shows the assessment of the predictive power of the Razor Model for these two metrics across all three interconnections in the 2010 to 2012 weekly backcasting exercise.

TABLE B-1

IHS power system Razor Model analysis

	East	West	ERCOT
Average wholesale power price difference	2.3	0.3	-3.8
Average production cost difference	-0.2	-4.7	-0.1

Note: Differences reflect deviation averaged over backcasting period. Production cost difference reflects average of five power sources: Coal, gas combined-cycle, gas combustion turbine, nuclear, and oil.

Source: IHS Energy

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Viewpoint

Should commissions pre-approve a gas utility's hedging activities?[1]

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1. The policy dilemma

Some gas utilities have recently asked their state public utility commissions (PUCs) to pre-approve hedging plans that would reduce the volatility of natural gas prices to a utility and its customers. The major argument made by these utilities is that the vulnerability of hedging activities to second-guessing, especially when financial instruments are involved, justifies pre-approval of a hedging plan in addition to the associated costs. These gas utilities thus believe that receiving commission support of a hedging strategy up-front is critical in mitigating ex post prudence risk in the form of appropriation or exploitation.

Taking a different position in state commission proceedings are those who have argued that pre-approval should be contingent on the utility providing evidence that the hedging plan would be beneficial to customers and that the utility would have strong incentives to efficiently carry out the plan.[2] Their concern is that customers may end up paying higher prices for price stability to which they attach little benefit. They also have expressed the fear that pre-approval would exonerate a utility from accountability for its actions in executing a pre-approved hedging plan. In effect, opponents of pre-approval have argued that firming a commission's commitment up-front to a particular hedging plan may magnify the incentive (moral hazard) problem arising from the principal-agent relationship between a commission and a utility.[3]

Throughout their history, state PUCs have been reluctant to foreclose binding themselves or future commissions from exercising certain actions that may be deemed by them to be appropriate under the circumstances. The asymmetric problem where the utility has superior information to the commission provides a defense for a commission to not fully commit itself up-front to a utility's actions and the associated costs.[4] In this paper, it is argued that the optimal policy for a commission would likely be less than full commitment, in the process making customers not as vulnerable to opportunistic behavior by the utility. The optimal policy would seem to lie somewhere between strict pre-approval and no guidance by a commission up-front as to how it would review a particular utility activity. Guidance in the form of ex ante rules or guidelines, for

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[2] As an example, last year in Maine a Hearing Examiner rejected a hedging plan proposal by Northern Utilities. The proposal called for the approval of a hedging plan that would include futures contracts as a means of reducing the volatility of the price of natural gas. The proposal also requested that any transaction costs incurred in the purchase of futures contracts as well as any cost of administering the program be fully passed on to the utility's customers. In her report, the Hearing Examiner argued that the proposal amounts to pre-approval of the added costs of a hedging plan that may not provide any benefits for ratepayers and does not contain performance incentives for the utility. The state's public advocate argued that weak incentives would result in the utility passively managing the hedging program, contending that [c]ontinuous oversight and management of a hedging plan is necessary and will be fostered only when the Company shares in both the costs and benefits. The public advocate also argued that the program does not require pre-approval from the Commission, and that consumers may not be willing to pay the cost that would be required of them for having price stability.

[3] As another example, in Massachusetts, Bay State Gas' proposed hedging plan was criticized by marketers and the state's Attorney General. They argued that the proposal would weaken competition and has the potential to harm customers as well by raising gas costs. The Attorney General asserted that the Commission should allow the competitive market to provide gas sales services with capped prices or any other pricing variations, created with or without hedging. In a separate Commission investigation, the Attorney General strongly recommended against allowing LDCs to hedge with financial derivatives. Among other things, the Attorney General argued that hedging with financial derivatives has not been shown to provide net benefits to consumers and that hedging can produce huge losses.

[4] See, for example, Blackmon and Zeckhauser (1992) and Blank and Pomerance (1992).

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example, could reflect the commitment of a commission on how it would evaluate the outcomes of a hedging program.

2. Major questions

A major question for regulators should be whether, in the absence of pre-approval, the uncertainty of hedging would be so great as to discourage a utility from hedging when it would be in the public interest to do so. On the one hand, too much uncertainty may cause a utility to rationally respond by not hedging. For example, high uncertainty of cost recovery for hedging activities may motivate a utility to purchase all of its natural gas in the spot market. On the other hand, minimizing uncertainty by pre-approving all costs before they are actually incurred may create perverse incentives for a utility in managing its hedging strategy. After all, once a hedging strategy is in place a utility typically will be making critical decisions during the entire time period of its hedging plan. Most experts would agree that an appropriate hedging plan should provide for flexibility of tactics because of intervening events and updated information. Thus, it would seem to be bad policy for a commission to presume the prudence of costs before they can be precisely specified and are actually incurred—as mentioned above, perverse incentives could otherwise easily result.

There is also the argument that the benefits of hedging to the utility can offset the risk of hedging even under the threat of cost disallowance. One of these benefits would include eliminating the imprudence risk from not hedging. This risk is just as real, and arguably can be of greater magnitude than the risk of hedging when, ex post, it was the wrong thing to do. The failure of a utility to hedge could also drive up its bad debt, damage its goodwill, and reduce its competitiveness.[5] All in all, we can see here the difficulty in determining what would be an optimal regulatory policy on hedging.

In the case of purchased gas costs, in most states past incurred costs are evaluated after-the-fact, frequently under the rebuttable-presumption-of-prudence standard (i.e., a standard whereby parties contesting prudence must provide unambiguous evidence of unreasonable conduct by a utility) and without the benefit of 20–20 hindsight. Axiomatically, the prudence test requires only reasonableness under the circumstances at the time a decision or action was taken, but, as it has been shown in practice, this condition is sometimes violated.

In pre-approving a utility's hedging plan, for example, a commission may want to ask whether the utility's price expectations, or more precisely the probability distribution of future prices, implicit in its hedging plan are compatible with the consensus forecasts of others (e.g., NYMEX futures prices adjusted for the "basis" component applicable to the market center or hub from which a utility purchases natural gas), or, if they weren't, what was the reason for the utility's deviation. In an ex post prudence review, price expectations should not be second-guessed in the sense that they turned out wrong and resulted in higher costs when they were previously considered to be reasonable by the commission in its pre-approval of the utility's hedging plan. In this case the utility should therefore not be held accountable if its price forecasts did not transpire, which seems inevitable and, therefore, expected for any hedging program. (Of course, if the utility is operating under some sort of symmetric incentive plan, then it should absorb the costs associated with forecasting errors, as well as reap the benefits of accurate forecasts, as actual outcomes rather than the reasonableness of decisions is the basis for cost recovery).

3. The nature of hedging

In contrast to gas procurement, hedging may be best viewed as a customer-oriented value-added service, with the commission arguably obligated to make the judgment of how much hedging (if any) would be preferred by customers.[6] I will argue later that such a policy would be well-founded given the inherent nature of hedging and the difficulties in measuring its benefits to customers.

As a matter of practice, neither a gas utility nor a commission has sufficient information to know precisely how much a utility should hedge, how it should hedge, or how much it should spend on hedging. For example, measuring customers' risk preferences in terms of how much customers are willing to pay to have more stable price is difficult to do.[7] Hedging costs are similarly problematic to measure given the highly dynamic nature of natural gas markets. The best that can be hoped for is a

[5] In recognizing the benefits of hedging to a gas utility, particularly since the winter of 2000–2001, the investment community has looked favorably upon utilities that manage the price risks associated with gas purchases.

[6] If this presumption is true, then it can be argued that the purchase of physical gas to meet customers' demand represents an activity distinct from price-risk management. Traditionally, before the advent of financial derivatives, gas procurement and price-risk management were bundled as one activity or product—for example, the case of forward contracts and storage. See, for example, Costello and Cita (2001).

[7] It is not absolutely clear that customers would prefer more stable prices if, in fact, they result in higher expected prices over time or require payment in the form of a "risk premium" to those parties willing to shoulder the risk. It is safe to say that customers have unequal risk tolerances—some customers would be willing to float with the market while others would be willing to pay something to have more stable prices.

reasonable but imperfect assessment of these components of a hedging plan so as to create a hedging strategy that seems from both the utility and commission perspective, given the limited information available, to be compatible with customer interests. This is perhaps the most valid argument for why a commission should partner with a gas utility in endorsing a hedging strategy up-front. Consequently, the commission may have to act as an agent on behalf of say core customers—i.e., customers who purchase commodity gas from the local utility even though they have the ability to choose another supplier—in giving support to a hedging strategy, or in rejecting a proposed hedging strategy in view of less than perfect information. Regulators should remember that a hedging strategy by a utility would likely increase the utility's expected costs over time since hedging involves paying someone to take on risk.[8]

In justifying guaranteed recovery of yet-to-be-incurred costs, the utility should have the burden of (1) demonstrating why the prudence test (which, as mentioned above, is normally used when assessing purchased gas costs and other costs recoverable through PGAs) would fail to give them incentive to hedge—for example, hedging is highly susceptible to a whimsical evaluation based on outcomes rather than the prudence of the decisions themselves, and (2) providing the commission with sufficient information up-front so that the commission could make an informed decision that would guarantee the recovery of all costs by the utility. Since pre-approval of costs results in the shifting of all risks to customers, a commission should invariably impose a high standard on a utility to demonstrate the merits of its proposed hedging plan or to argue that hedging is a special case making a traditional prudence review inappropriate. The high standard in support of a plan requires good data as well as sound analysis.

Conditions may prevail that justify pre-approval in preventing a utility from not undertaking an action that would be in consumers' interest. One such condition is that a utility would be highly susceptible to 20–20 hindsight because of the information difficulties for a utility to ever show that its hedging strategy was optimal.[9] This makes the utility especially vulnerable, when the outcome of the plan turned out negative, to the charge that it was imprudent to go ahead with a plan that it could not demonstrate to be optimal from the perspective of customers.

[8] As an aside, a better approach may involve individual customers revealing their preferences for price stability by choosing between a fixed-price tariff (if one is offered) and a traditional tariff or, under a customer choice program, between fixed-price service and variable-price service from a marketer.

[9] As noted earlier, 20–20 hindsight falls outside the legal interpretation of a prudence test but not always outside the realm of commission consideration.

4. A proposal

The major message presented in this paper is that a commission should provide guidance to a utility on the general features of an acceptable hedging plan and actually approve a plan itself, but with the condition that it should not guarantee up-front that all of the costs associated with the plan will ultimately be recovered from customers.[10] After all, a plan can be found acceptable, which should significantly narrow the scope of a prudence review, without committing the commission beforehand to allow a utility full recovery of the costs actually incurred. While there is a strong link between a hedging plan and the costs incurred, these costs are also dependent upon how the plan was executed and managed. Admittedly, an evaluation of execution and management after-the-fact could be quite subjective, although it may involve little more than auditing the utility's compliance plan for its conformity with its pre-approved hedging strategy. As a general rule, as long as the utility acted within the bounds of a pre-approved hedging plan, however that is determined, no cost disallowance should take place. Of course, good public policy dictates that a commission should always leave open until after the fact whether the utility acted consistently with a hedging plan even if the plan itself was previously approved, and found to be reasonable, by the commission. As an analogy, a football coach may have a good game plan, but if he failed to execute the plan because of poor communications with his players, he should be held accountable for any poor performance that may result. In other words, he should be blamed—rather than his players—if he is unable to convey to them how the plan should be carried out.

Thus, even if a commission pre-approves a hedging plan, it should not presume all of the costs associated with the plan to be prudent and recoverable from customers. But, to be fair to the utility and, additionally, to avoid discouraging the utility from hedging, a pre-approved plan should significantly reduce the scope of any prudence review. As discussed below, this would not only reduce uncertainty for the utility, but it would also make it much easier for a commission to determine after-the-fact whether the outcome fell within the bounds of reasonable decision-making on the part of the utility (i.e., the utility acted "prudently" in the traditional sense of the term).

In mitigating unnecessary uncertainty for the utility, a commission should seriously consider establishing guidelines up-front that outline the objectives and features of an acceptable hedging plan as well as criteria for cost recovery by a utility. For example, a commission

[10] Support for guidelines and what guidelines would entail are discussed in Costello and Cita (2001).

should articulate up-front its position on the objective of a hedging plan—one possible candidate is to prevent prices charged to customers from exceeding a specified level. Guidelines can pertain to the program parameters such as the volume of gas to be hedged, the total budget for hedging, the mix of hedging instruments to be used, and discretionary actions that could be taken by management or its contractor during the hedging period. Guidelines can also encompass program monitoring and reporting requirements that might include a utility's review of the program's prior performance.[11]

Up-front guidelines and criteria for cost recovery can eliminate much of the contentious debate that would otherwise arise during a prudence review. As good regulatory policy, a utility needs clear signals from a commission as to the acceptable objective of a hedging strategy and what would be considered reasonable tactics. Overall, the utility needs to know the rules under which it will make decisions. Otherwise, the utility would be more reluctant to hedge even when, from the customers' perspective, it is the right thing to do.

Specifically, I would advise commissions to: (1) establish up-front rules, including prudence criteria, (2) sign-off on a hedging strategy if it deems (although one never knows for sure) to be in the customers' interest, (3) evaluate after-the-fact the execution and management of a commission-approved hedging strategy to determine whether the utility acted within the confines of an pre-approved hedging strategy, and (4) as a side condition, not micromanage hedging tactics once a strategy is in place. I believe that the proper balance in a commission policy lies with giving the utility a great deal of certainty up-front without forfeiting the commission's right to question whether some of the costs actually incurred were imprudent and unreasonable.

Utilities have a right to feel vulnerable to an after-the-fact regulatory interpretation of outcomes that resemble Monday morning quarterbacking—by design, hedging is expected to result in a net loss to consumers (analogous to the purchase of insurance when the insured party doesn't make a claim) and, as argued above, it is inherently next to impossible for a utility to argue after-the-fact that its hedging strategy was optimal. Similarly, even under a rebuttal presumption of prudence, an outside party might argue that a utility's strategy was not optimal because it did not take into account customers' preferences for risk aversion (i.e., more stable prices) in addition to not explicitly calculating the costs associated with different hedging instruments.

I would advise commissions to go as far as signing off on a hedging strategy in alleviating what I would regard as a legitimate fear by utilities. In doing so, commissions should articulate that they will not evaluate the prudence of costs with the benefit of 20–20 hindsight and will consider any cost reasonable that falls within the guidelines of the hedging strategy. For example, hedging can be rightly judged as successful and prudent even when prices turned out higher than what they would have been in the absence of hedging.[12]

To recap, a utility is most susceptible to the charge when the results of its hedging strategy turn out bad that "Why did you go ahead with hedging when you had incomplete information? Isn't it imprudent to go ahead with a hedging plan when you didn't know whether consumers would be better off or you didn't know, at least you didn't show this beforehand, that your hedging strategy was least cost?" Unless a commission gives the utility approval up-front to execute a particular plan, it is clearly understandable why a utility would be reluctant to hedge. Without pre-approval, the utility is placed in the predicament of "dammed if we do, dammed if we don't." This translates into "if we do hedge and the outcome is negative, we'll probably get slammed; if we don't hedge and market prices unexpectedly go up, we'll also get slammed." Boxing a utility into such a corner would be both unfair to the utility and potentially costly to customers, for example, as the utility's cost of capital would likely increase.

5. Information problems

Two major questions should underlie an ex ante evaluation of a hedging strategy: (1) does the utility's strategy reflect the preferences of its customers for stable prices, which is difficult given the varying preferences among customers, and (2) does the strategy represent least-cost hedging (for example, hedging that results in minimum transaction costs for the utility), taking into account the myriad hedging tools available for use? In establishing a prudence standard for hedging, a commission should specify up-front an acceptable level of price volatility or consumer risk tolerance toward price volatility, in addition to defining an acceptable average cost for gas including the costs associated with hedging.

In practice, however, it is difficult to acquire data on how much the "average customer" would be willing to pay to have the utility hedge and, therefore, to determine whether hedging costs are prudent in terms of benefiting customers. In addition, not knowing the degree and nature of customers' preference for price stability also makes it highly difficult for both the utility and the commission to determine the right mix of hedging instruments. For example, if evidence points to customers

[11] See, for example, Costello and Cita (2001).

[12] The reason for this is that even though consumers (who are assumed to be risk averse) end up paying higher prices they benefit from knowing that hedging would prevent them from having to pay extremely high prices.

being only concerned with avoiding catastrophic prices, such as natural gas prices above $8 per Mcf, then options and swaps may be the preferred financial instruments, rather than collars and futures contracts. As an illustration, with the objective of avoiding extremely high prices, the optimal approach for a utility might be to purchase inexpensive call options with a strike price far in excess of the current or expected market price.

The lack of precise information on the value customers place on hedging and what constitutes a least-cost hedging strategy complicates both the utility defense of its strategy and its evaluation by a commission. One implication of this is that a utility may be hard pressed to demonstrate up-front or after-the-fact that its plan is or was reasonably compatible with consumer interests and least cost in nature. As argued here, the commission should then assume the role of an agent on behalf of consumers in determining both the level of hedging and the mix of hedging instruments to be used.[13] Of course, if a prudence review is conducted, presumably there is a rebuttable presumption that the utility acted prudently, with the burden shifted to other parties in providing evidence that the utility acted imprudently given the information it had and should have had at the time of its decision.[14]

It should be noted that in executing a hedging plan a utility would likely be making numerous decisions throughout the period of its plan. An effective hedging plan would often require the utility or its contractor to pro-actively make critical decisions at times of changing market conditions. To say differently, a good plan would provide the utility with flexibility to adapt to varied market conditions. Those contesting a utility's recovery of hedging cost after-the-fact would therefore have to evaluate all of the key decisions made by the utility over the time horizon of the hedging plan. Along with trying to argue that a utility's hedging plan was imprudent because it failed to explicitly take into account consumers' preferences for stable prices or the relative costs of different hedging instruments, this dynamic decision-making process further complicates a showing of imprudence.

6. Conclusion

This paper proposes that good regulation would include (1) pre-approval of a hedging plan (as noted earlier, hedging is especially susceptible to 20–20 hindsight review when it results in higher average cost during a time of unexpected falling natural gas prices), (2) a review of the actual costs incurred in carrying out the hedging plan as to their conformance with the tactics incorporated into the pre-approved plan (with pre-approval, the scope of prudence reviews would be greatly narrowed), and (3) a recognition that hedging with financial instruments represents an activity distinct from traditional gas procurement. Under this regulatory policy, the utility would be required to provide sufficient support up-front if it expects to receive pre-approval of its hedging plan. Data and analytical limitations preclude, however, finding the optimal hedging plan.

At best, commissions can only judge whether a particular hedging plan seems reasonable and at least in line with a rough assessment of customers' preferences and other information available at the time. A margin of error inevitably exists in the development of any hedging plan. Commissions should be cognizant of this reality in signing off on a utility's plan as well as in any prudence review that may occur later.

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Costello, K.W., Cita, J., 2001. Use of Hedging by Local Gas Distribution Companies: Basic Considerations and Regulatory Issues. The National Regulatory Research Institute, Columbus, OH.

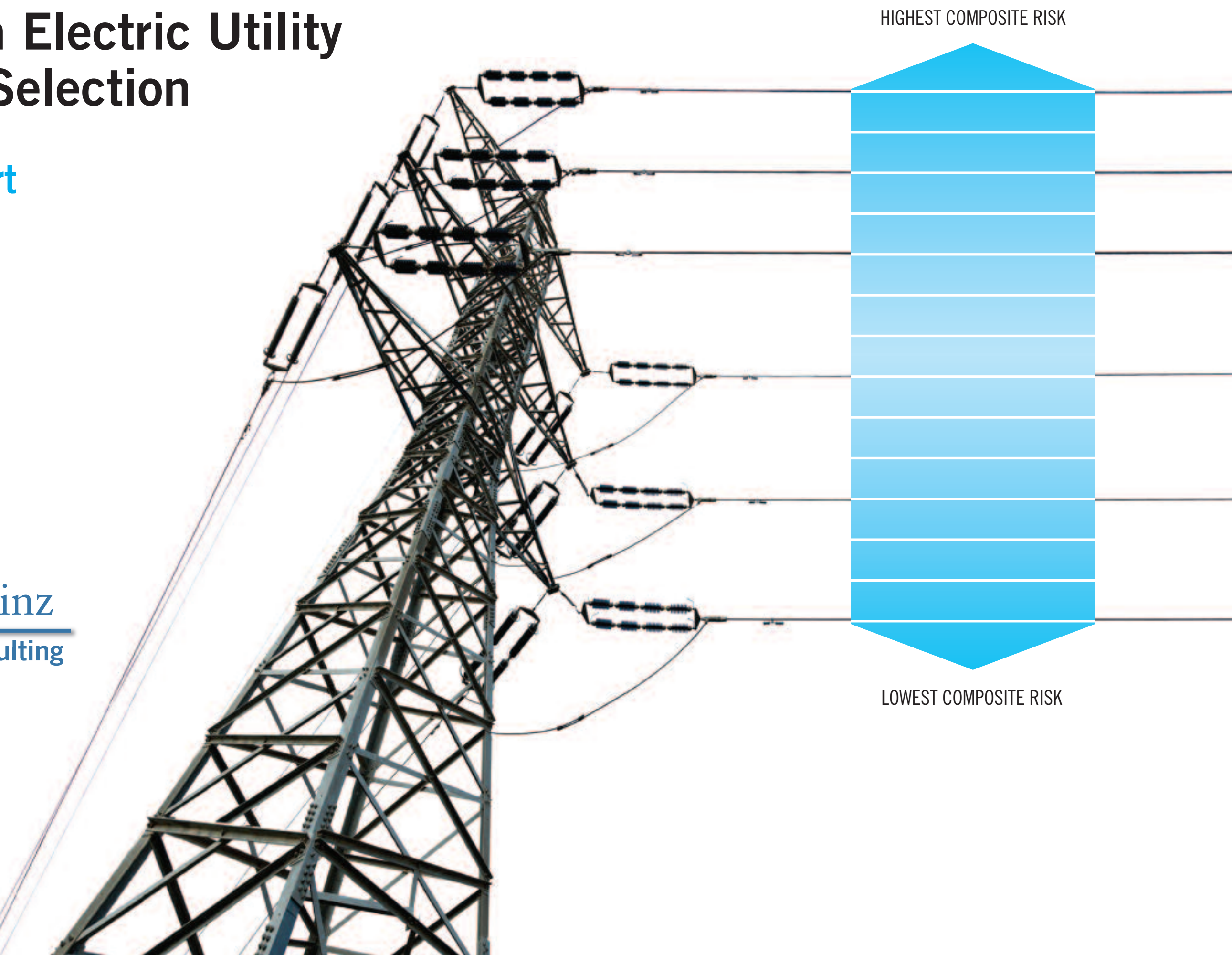
[13] In a general sense, a public utility commission is seen by most regulatory experts as an agent for consumers in its role of protecting them against exploitation by a utility granted ex facto monopoly status.

[14] In practice, however, the regulator may require the utility to demonstrate that its actions were prudent.

Ceres

PRACTICING RISK-AWARE ELECTRICITY REGULATION: What Every State Regulator Needs to Know

How State Regulatory Policies Can Recognize and Address the Risk in Electric Utility Resource Selection



A Ceres Report
April 2012

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Ceres is an advocate for sustainability leadership. It leads a national coalition of investors, environmental groups and other public interest organizations working with companies to address sustainability challenges. Ceres also directs the Investor Network on Climate Risk (INCR), a network of 100 institutional investors with collective assets totaling about $10 trillion.

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ABOUT THIS REPORT

AUDIENCE

This report is primarily addressed to **state regulatory utility commissioners**, who will preside over some of the most important investments in the history of the U.S. electric power sector during perhaps its most challenging and tumultuous period. This report seeks to provide regulators with a thorough discussion of risk, and to suggest an approach—"risk-aware regulation"—whereby regulators can explicitly and proactively seek to identify, understand and minimize the risks associated with electric utility resource investment. It is hoped that this approach will result in the efficient deployment of capital, the continued financial health of utilities, and the confidence and satisfaction of the customers on whose behalf utilities invest.

Additionally, this report seeks to present a unique discussion of risk and a perspective on appropriate regulatory approaches for addressing it that will interest numerous **secondary audiences**, including **utility managements, financial analysts, investors, electricity consumers, advocates, state legislatures and energy offices, and other stakeholders** with a particular interest in ensuring that electric system resource investments—which could soon reach unprecedented levels—are made thoughtfully, transparently and in full consideration of all associated risks.

SCOPE

While we believe that the approach described herein is applicable to a broad range of decisions facing state regulators, the report focuses primarily on resource investment decisions by investor-owned electric utilities (IOUs), which constitute roughly 70 percent of the U.S. electric power industry. The findings and recommendations may be of particular interest to regulators in states facing substantial coal generating capacity retirements and evaluating a spectrum of resource investment options.

AUTHORS

Ron Binz, the lead author of this report, is a 30-year veteran of utility and energy policy and principal with Public Policy Consulting. Most recently, he served for four years as the Chairman of the Colorado Public Utilities Commission where he implemented the many policy changes championed by the Governor and the Legislature to bring forward Colorado's "New Energy Economy." He is the author of several reports and articles on renewable energy and climate policy has testified as an expert witness in fifteen states.

Richard Sedano is a principal with the Regulatory Assistance Project (RAP), a global, non-profit team of experts focused on the long-term economic and environmental sustainability of the power and natural gas sectors, providing technical and policy assistance to policymakers and regulators on a broad range of energy and environmental issues. RAP is widely viewed as a source of innovative and creative thinking that yields practical solutions. RAP members meet directly with government officials, regulators and their staffs; lead technical workshops and training sessions; conduct in-house research and produce a growing volume of publications designed to better align energy regulation with economic and environmental goals.

Denise Furey has over 25 years of experience with financial institutions, structuring and analyzing transactions for energy and utility companies. In 2011 she founded Regent Square Advisors, a consulting firm specializing in financial and regulatory concerns faced by the sector. She worked with Citigroup covering power and oil & gas companies, and worked with Fitch Rating, Enron Corporation and MBIA Insurance Corporation. Ms. Furey also served with the Securities and Exchange Commission participating in the regulation of investment companies.

Dan Mullen, Senior Manager for Ceres' Electric Power Programs, works to identify and advance solutions that will transform the U.S. electric utility industry in line with the urgent goal of sustainably meeting society's 21st century energy needs. In addition to developing Ceres' intellectual capital and external partnerships, he has engaged with major U.S. electric utilities on issues related to climate change, clean energy and stakeholder engagement, with a particular focus on energy efficiency. A Stanford University graduate, Dan has also raised more than $5 million to support Ceres' climate change initiatives and organizational development.

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FOREWORD

Today's electric industry faces a stunning investment cycle. Across the country, the infrastructure is aging, with very old parts of the power plant fleet and electric and gas delivery systems needing to be replaced. The regulatory environment is shifting dramatically as rules tighten on air pollution from fossil-burning power plants. Fossil fuel price outlooks have shifted. New options for energy efficiency, renewable energy, distributed generation, and smart grid and consumer technologies are pressing everyone to think differently about energy and the companies that provide it. Customers expect reliable electricity and count on good decisions of others to provide it.

The critical nature of this moment and the choices ahead are the subject of this report. It speaks to key decision-makers, such as: state regulators who have a critical role in determining utility capital investment decisions; utility executives managing their businesses in this era of uncertainty; investors who provide the key capital for utilities; and others involved in regulatory proceedings and with a stake in their outcomes.

The report lays out a suite of game-changing recommendations for handling the tremendous investment challenge facing the industry. As much as $100 billion will be invested each year for the next 20 years, roughly double recent levels. A large portion of those investments will be made by non-utility companies operating in competitive markets. But another large share will be made by utilities—with their (and their key investors') decisions being greatly affected by state regulatory policies and practices.

This is no time for backward-looking decision making. It is vital—for electricity consumers and utilities' own economic viability—that their investment decisions reflect the needs of tomorrow's cleaner and smarter 21st century infrastructure and avoid investing in yesterday's technologies. The authors provide useful advice to state regulators on how they can play a more proactive role in helping frame how electric utilities face these investment challenges.

A key report conclusion in this regard: sensible, safe investment strategies, based on the report's detailed cost and risk analysis of a wide range of generation resources, should include:

- Diversifying energy resource portfolios rather than "betting the farm" on a narrow set of options (e.g., fossil fuel generation technologies and nuclear);
- More emphasis on renewable energy resources such as onshore wind and distributed and utility-scale solar;
- More emphasis on energy efficiency, which the report shows is utilities' lowest-cost, lowest-risk resource.

At its heart, this report is a call for "risk-aware regulation." With an estimated $2 trillion of utility capital investment in long-lived infrastructure on the line over the next 20 years, regulators must focus unprecedented attention to risk—not simply keeping costs down today, but minimizing overall costs over the long term, especially in the face of possible surprises. And utilities' use of robust planning tools needs to be sharpened to incorporate risk identification, analysis, and management.

This report offers some good news amid pervasive uncertainty: the authors point out that planning the lowest-cost, lowest risk investment route aligns with a low-carbon future. From a risk management standpoint, diversifying utility portfolios today by expanding investment in clean energy and energy efficiency makes sense regardless of how and when carbon controls come into play. Placing too many bets on the conventional basket of generation technologies is the highest-risk route, in the authors' analysis.

We're in a new world now, with many opportunities as well as risks. More than ever, the true risks and costs of utility investments should be made explicit and carefully considered as decisions on multi-billion-dollar commitments are made.

As the industry evolves, so too must its regulatory frameworks. The authors point out why and offer guidance about how. This is news regulators and the industry can use.

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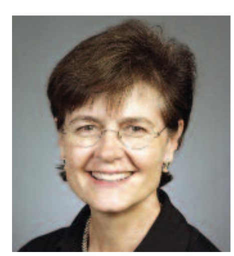


EXECUTIVE SUMMARY

CONTEXT: INCREASING CAPITAL INVESTMENT BY U.S. ELECTRIC UTILITIES AMID HISTORIC UNCERTAINTY AND RISK

The U.S. electric utility industry, which has remained largely stable and predictable during its first century of existence, now faces tremendous challenges. Navigant Consulting recently observed that "the changes underway in the 21st century electric power sector create a level and complexity of risks that is perhaps unprecedented in the industry's history."[1] These challenges include:

- an aging generation fleet and distribution system, and a need to expand transmission;
- increasingly stringent environmental regulation limiting pollutants and greenhouse gases;[2]
- disruptive changes in the economics of coal and natural gas;
- rapidly evolving smart grid technologies enabling greater customer control and choice;
- increased policy maker emphasis on demand-side resources requiring new regulatory approaches and utility business models;
- competition from growth in distributed generation;
- slow demand growth due to protracted economic recovery and high unemployment;
- substantially weakened industry financial metrics and credit ratings, with over three-quarters of companies in the sector rated three notches or less above "junk bond" status.[3]

Many of these same factors are driving historic levels of utility investment. It is estimated that the U.S. electricity industry could invest as much as $100 billion each year for 20 years[4]—roughly twice recent investment levels. This level of investment will double the net invested capital in the U.S. electricity system by 2030. Moreover, these infrastructure investments are long lived: generation, transmission and distribution assets can have expected useful lives of 30 or 40 years or longer. This means that many of these assets will likely still be operating in 2050, when electric power producers may be required to reduce greenhouse gas emissions by 80 percent or more to avoid potentially catastrophic impacts from climate change.

1 Forrest Small and Lisa Frantzis, *The 21st Century Electric Utility: Positioning for a Low-Carbon Future*, Navigant Consulting (Boston, MA: Ceres, 2010), 28, http://www.ceres.org/resources/reports/the-21st-century-electric-utility-positioning-for-a-low-carbon-future-1.

2 Estimates of U.S. coal-fired generating capacity that could be retired in the 2015-2020 timeframe as a result of forthcoming U.S. Environmental Protection Agency (EPA) air quality regulations range from 10 to 70 gigawatts, or between three and 22 percent of U.S. coal-fired generation capacity. Forthcoming EPA water quality regulations could require the installation of costly cooling towers on more than 400 power plants that provide more than a quarter of all U.S. electricity generation. See Susan Tierney, "Electric Reliability under New EPA Power Plant Regulations: A Field Guide," *World Resources Institute*, January 18, 2011, http://www.wri.org/stories/2011/01/electric-reliability-under-new-epa-power-plant-regulations-field-guide.

3 Companies in the sector include investor-owned utilities (IOUs), utility holding companies and non-regulated affiliates.

4 Marc Chupka et al., *Transforming America's Power Industry: The Investment Challenge 2010-2030*, The Brattle Group (Washington DC: The Edison Foundation, 2008), vi, http://www.brattle.com/_documents/UploadLibrary/Upload725.pdf. Brattle's investment estimates apply to the entire U.S. electric utility industry, including IOUs, electric cooperatives and government-owned utilities. From 2000-05, overall annual capital expenditures by U.S. IOUs averaged roughly $48 billion; from 2006-10 that number climbed to $74 billion; see Edison Electric Institute, *2010 Financial Review: Annual Report of the U.S. Shareholder-Owned Electric Utility Industry* (Washington DC: Edison Electric Institute, 2011), 18, http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/finreview/Documents/FR2010_FullReport_web.pdf.

Greatly increased utility investment combined with minimal, zero or even declining electricity demand growth means that retail electricity prices for consumers will rise sharply, claiming a greater share of household disposable income and likely leading to ratepayer resistance.[5] Because the U.S. economy was built on relatively cheap electricity—the only thing many U.S. consumers and businesses have ever known—credit rating agencies are concerned about what this dynamic could mean for utilities in the long term. Rating analysts also point out that the overall credit profile for investor-owned utilities (IOUs) could decline even further since utilities' operating cash flows won't be sufficient to satisfy their ongoing investment needs.[6]

It falls to state electricity regulators to ensure that the large amount of capital invested by utilities over the next two decades is deployed wisely. Poor decisions could harm the U.S. economy and its global competitiveness; cost ratepayers, investors and taxpayers hundreds of billions of dollars; and have costly impacts on the environment and public health.

To navigate these difficult times, it is essential that regulators understand the risks involved in resource selection, correct for biases inherent in utility regulation, and keep in mind the long-term impact that their decisions will have on consumers and society. To do this, regulators must look outside the boundaries established by regulatory tradition.

CHALLENGES TO EFFECTIVE REGULATION

To be effective in the 21st century, regulators will need to be especially attentive to two areas: identifying and addressing risk; and overcoming regulatory biases.

Risk arises when there is potential harm from an adverse event that can occur with some degree of probability. Put another way, risk is "the expected value of a potential loss." *Higher risk* for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Risks for electric system resources have both time-related and cost-related aspects. *Cost risks* reflect the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations. *Time risks* reflect the possibility that circumstances will change over the life of the investment and materially affect both the cost of the investment and the degree to which it benefits consumers. **Figure ES-1** summarizes the many varieties of risk for utility resource investment.

Risk is the expected value of a potential loss. Higher risk for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Figure ES-1

VARIETIES OF RISK FOR UTILITY RESOURCE INVESTMENT

Cost-related	*Time-related*
Construction costs higher than anticipated	Construction delays occur
Availability and cost of capital underestimated	Competitive pressures; market changes
Operation costs higher than anticipated	Environmental rules change
Fuel costs exceed original estimates, or alternative fuel costs drop	Load grows less than expected; excess capacity
Investment so large that it threatens a firm	Better supply options materialize
Imprudent management practices occur	Catastrophic loss of plant occurs
Resource constraints (e.g., water)	Auxiliary resources (e.g., transmission) delayed
Rate shock: regulators won't put costs into rates	Other government policy and fiscal changes

5 Moody's Investors Service, *Special Comment: The 21st Century Electric Utility* (New York: Moody's Investors Service, 2010). Importantly, customers who currently enjoy the lowest electricity rates can expect the largest rate increases, in relative terms, as providers of cheap, coal-generated electricity install costly pollution controls or replace old coal-fired units with more expensive new resources. This dynamic could prove especially challenging for regulators, utilities and consumers in the heavily coal-dependent Midwest.

6 Richard Cortright, "Testimony before the Pennsylvania Public Utility Commission," Harrisburg, Pennsylvania, November 19, 2009, http://www.puc.state.pa.us/general/RegulatoryInfo/pdf/ARRA_Testimony-SPRS.pdf.

RISK

Three observations about risk should be stressed:

1. **Risk cannot be eliminated, but it can be managed and minimized.** Since risks are defined as probabilities, it is by definition probable that some risks will be realized—that, sooner or later, risk will translate into dollars for consumers, investors or both. This report concludes with recommendations for how regulators can minimize risk by practicing "risk-aware regulation."
2. **It is unlikely that consumers will bear the full cost of poor utility resource investment decisions.** The very large amount of capital investment that's being contemplated and the resulting upward pressure on electricity rates will make it very unappealing (or simply untenable) for regulators to burden ratepayers with the full cost of utility mistakes. As a result, it is likely that utility investors (specifically shareholders) will be more exposed to losses resulting from poor utility investment decisions than in years past.
3. **Ignoring risk is not a viable strategy.** Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate. Following a practice just because "it's always been done that way," instead of making a fresh assessment of risk and attempting to limit that risk, is asking for trouble.

Traditional utility regulation also contains several built-in biases that effective regulators must overcome.[7] These biases, which result in part from the incentives that traditional regulation provides to utilities, encourage utilities to invest more than is optimal for their customers—which is to say, more than is optimal for the provision of safe, reliable, affordable and environmentally sustainable electricity—and discourage them from investing in the lowest-cost, lowest-risk resources (namely, demand-side resources such as energy efficiency) that provide substantial benefits to ratepayers and local economies. Bias can also lead utilities to seek to exploit regulatory and legislative processes as a means of increasing profits (rather than, for example, improving their own operational efficiencies). Finally, regulators face an inherent information deficit when dealing with utility managements. This can hamper effective collaboration around utility planning, which is arguably the most important function of electricity regulation today.

COSTS AND RISKS OF NEW GENERATION RESOURCES

We closely examine costs and risks of new generation resources for several reasons. First, as the largest share of utility spending in the current build cycle, generation investment is where the largest amount of consumer and investor dollars is at risk. Also, today's decisions about generation investment can trigger substantial future investments in transmission and distribution infrastructure. Proposed power plants can be a lightning rod for controversy, heightening public scrutiny of regulatory and corporate decision-makers. Finally, poor investment decisions about generation resources in IOUs' last major build cycle resulted in tens of billions of dollars of losses for consumers and shareholders.[8] For these and other reasons, it is especially important that regulators address, manage and minimize the risks associated with utility investments in new generation resources.[9]

Ignoring risk is not a viable strategy. Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate.

Acquiring new electric system resources involves dimensions of both cost and risk. Of these two dimensions, the tools for estimating the cost elements of new generation, while imperfect, are more fully developed than the risk-related tools. As a starting point for our examination of the relative cost and risk of new generation resources, we rank a wide range of supply-side resources and one demand-side resource (energy efficiency) according to their levelized cost of electricity, or "LCOE" **(Figure ES-2, p. 8)**.[10] This ranking is based on 2010 data and does not include recent cost increases for nuclear or cost decreases for solar PV and wind. Because carbon controls could add significant costs to certain technologies but the exact timing and extent of these costs is unknown, we include a moderate estimate for carbon cost for fossil-fueled resources. And because incentives such as tax credits and loan guarantees can significantly affect LCOE, we examine the LCOE range for each technology with and without incentives where applicable.

7 These biases, which are discussed further in the report, are *information asymmetry; the Averch-Johnson effect; the throughput incentive; "rent-seeking"*; and *the "bigger-is-better" bias.*

8 Frank Huntowski, Neil Fisher, and Aaron Patterson, *Embrace Electric Competition or It's Déjà Vu All Over Again* (Concord, MA: The NorthBridge Group, 2008), 18, http://www.nbgroup.com/publications/Embrace_Electric_Competition_Or_Its_Deja_Vu_All_Over_Again.pdf. The NorthBridge Group estimates that ratepayers, taxpayers and investors were saddled with $200 billion (in 2007 dollars) in "above-market" costs associated with the build cycle of the 1970s and 80s. Between 1981-91, shareholders lost roughly $19 billion as a result of regulatory disallowances of power plant investments by some regulated utilities; see Thomas P. Lyon and John W. Mayo, "Regulatory opportunism and investment behavior: evidence from the U.S. electric utility industry," *Rand Journal of Economics*, Vol. 36, No. 3 (Autumn 2005): 628–44, http://webuser.bus.umich.edu/tplyon/PDF/Published%20Papers/Lyon%20Mayo%20RAND%202005.pdf. The potential for negative consequences is probably higher today; since the 1980s, electric demand has grown significantly while the environmental risks associated with utility operations, the costs of developing new generation resources, and the pace of technology development have all increased substantially.

9 While our analysis of risks and costs of new generation resources may be of most interest to regulators in "vertically-integrated" states (where utilities own or control their own generation), it also has implications for regulators in restructured states. Regulators in all states can direct electric utilities to invest in cost-effective demand-side resources, which, as this report makes clear, are utilities' lowest-cost and lowest-risk resources.

10 LCOE indicates the cost per megawatt-hour for electricity over the life of the plant, encompassing all expected costs (e.g., capital, operations and maintenance, and fuel). We primarily reference LCOE data compiled by the Union of Concerned Scientists (UCS), which aggregates three common sources of largely consensus LCOE data: the U.S. Energy Information Administration (EIA), the California Energy Commission (CEC) and the investment firm Lazard; see Barbara Freese et al., *A Risky Proposition* (Cambridge, MA: Union of Concerned Scientists, 2011), http://www.ucsusa.org/assets/documents/clean_energy/a-risky-proposition_report.pdf. LCOE costs for technologies not included in UCS's analysis (viz., biomass co-firing, combined cycle natural gas generation with CCS, and distributed solar) were estimated by the authors based on comparable resources referenced by UCS.

Figure ES-2

RELATIVE COST RANKING OF NEW GENERATION RESOURCES

HIGHEST LEVELIZED COST OF ELECTRICITY (2010)

- Solar Thermal
- Solar—Distributed*
- Large Solar PV*
- Coal IGCC-CCS
- Solar Thermal w/ incentives
- Coal IGCC
- Nuclear*
- Coal IGCC-CCS w/ incentives
- Coal IGCC w/ incentives
- Large Solar PV w/ incentives*
- Pulverized Coal
- Nuclear w/ incentives*
- Biomass
- Geothermal
- Biomass w/ incentives
- Natural Gas CC-CCS
- Geothermal w/ incentives
- Onshore Wind*
- Natural Gas CC
- Onshore Wind w/ incentives*
- Biomass Co-firing
- Efficiency

LOWEST LEVELIZED COST OF ELECTRICITY (2010)

Figure ES-3

RELATIVE RISK RANKING OF NEW GENERATION RESOURCES

HIGHEST COMPOSITE RISK

- Nuclear
- Pulverized Coal
- Coal IGCC-CCS
- Nuclear w/ incentives
- Coal IGCC
- Coal IGCC-CCS w/ incentives
- Natural Gas CC-CCS
- Biomass
- Coal IGCC w/ incentives
- Natural Gas CC
- Biomass w/ incentives
- Geothermal
- Biomass Co-firing
- Geothermal w/ incentives
- Solar Thermal
- Solar Thermal w/ incentives
- Large Solar PV
- Large Solar PV w/ incentives
- Onshore Wind
- Solar—Distributed
- Onshore Wind w/ incentives
- Efficiency

LOWEST COMPOSITE RISK

** Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

But the LCOE ranking tells only part of the story. The *price* for any resource in this list does not take into account the relative *risk* of acquiring it. To establish relative risk of new generation resources, we return to the many risks identified in Figure ES-1 and compress those risks into seven main categories:

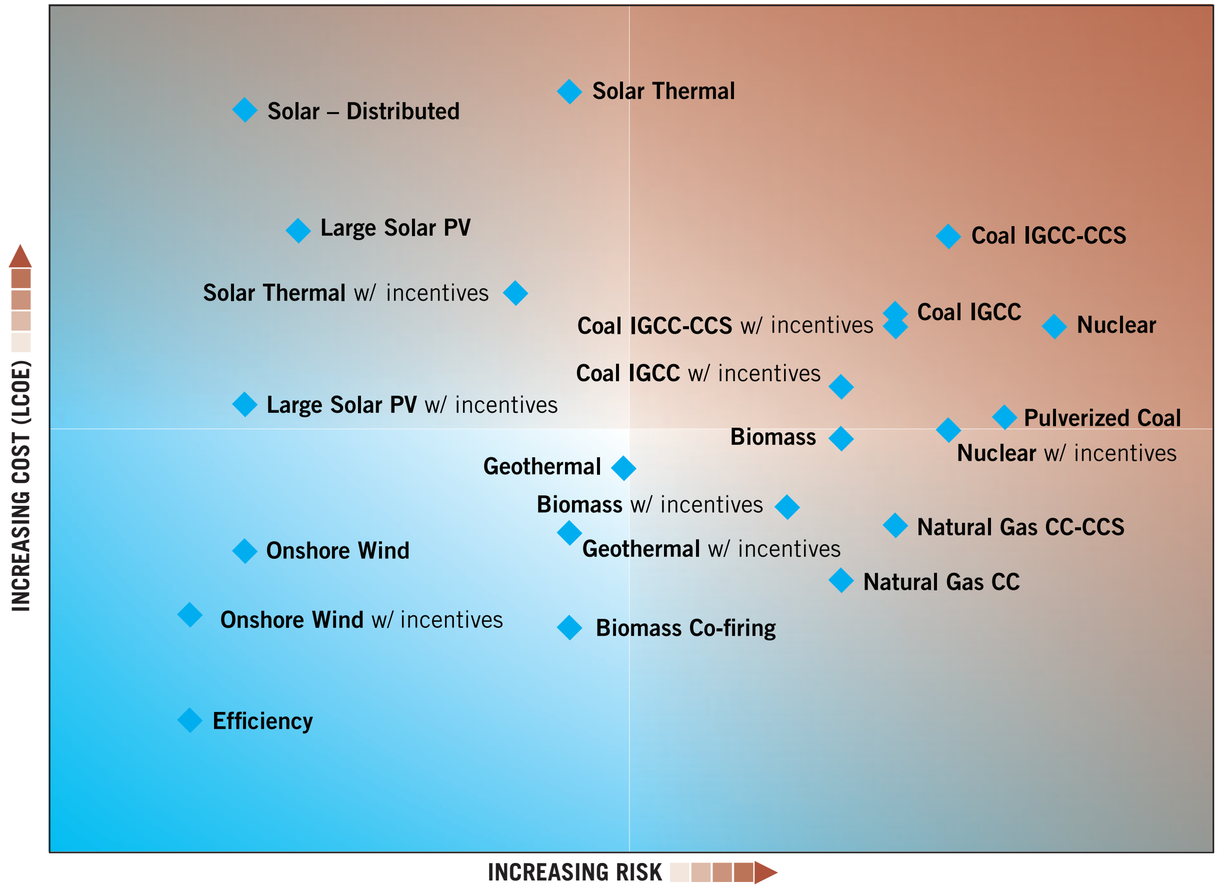
- **Construction Cost Risk:** includes unplanned cost increases, delays and imprudent utility actions
- **Fuel and Operating Cost Risk:** includes fuel cost and availability, as well as O&M cost risks
- **New Regulation Risk:** includes air and water quality rules, waste disposal, land use, and zoning
- **Carbon Price Risk:** includes state or federal limits on greenhouse gas emissions
- **Water Constraint Risk:** includes the availability and cost of cooling and process water
- **Capital Shock Risk:** includes availability and cost of capital, and risk to firm due to project size
- **Planning Risk:** includes risk of inaccurate load forecasts, competitive pressure

We then evaluate each resource profiled in the LCOE ranking and apply our informed judgment to quantify each resource's relative exposure to each type of risk.[11] This allows us to establish a composite risk score for each resource (with the highest score indicating the highest risk) and rank them according to their relative composite risk profile **(Figure ES-3)**.

11 Risk exposure in each risk category ranges from "None" to "Very High." We assigned scores (None = 0, Very High = 4) to each risk category for each resource and then summed them to establish an indicative quantitative ranking of composite risk. We also tested the robustness of the risk ranking by calculating two additional rankings of the risk scores: one that overweighted the cost-related risk categories and one that overweighted the environmental-related risk categories.

Figure ES-4

PROJECTED UTILITY GENERATION RESOURCES IN 2015
Relative Cost and Relative Risk



The risk ranking differs from the cost ranking in several important ways. First, the risk ranking shows a clear division between renewable resources and non-renewable resources. Second, nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

With largely consensus quantitative LCOE data, and having developed indicative composite risk scores for each resource, we can summarize relative risks and costs of utility generation resources in a single graph **(Figure ES-4)**.[12]

While this report focuses on new generation resources, the approach to "risk-aware regulation" described herein works equally well for the "retire or retrofit" decisions concerning existing coal plants facing regulators and utilities in many states.

While this report focuses on new generation resources, the approach to "risk-aware regulation" described herein works equally well for the "retire or retrofit" decisions concerning existing coal plants facing regulators and utilities in many states. The question for regulators is whether to approve coal plant closures in the face of new and future EPA regulations, or to approve utility investments in costly pollution controls to keep the plants running. Regulators should treat this much like an IRP proceeding: utilities should be required to present multiple scenarios differing in their disposition of the coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. In the end, regulators should enter a decision that addresses all of the relevant risks.

12 Resources are assumed to come online in 2015.

PRACTICING RISK-AWARE REGULATION: SEVEN ESSENTIAL STRATEGIES FOR STATE REGULATORS

MANAGING RISK INTELLIGENTLY IS ARGUABLY THE MAIN DUTY OF REGULATORS WHO OVERSEE UTILITY INVESTMENT. EFFECTIVELY MANAGING RISK IS NOT SIMPLY ACHIEVING THE LEAST COST *TODAY*, BUT RATHER IS PART OF A STRATEGY TO *MINIMIZE OVERALL COSTS OVER THE LONG TERM*. WE IDENTIFY SEVEN ESSENTIAL STRATEGIES THAT REGULATORS SHOULD EMPLOY TO MANAGE AND MINIMIZE RISK:

1. **DIVERSIFYING UTILITY SUPPLY PORTFOLIOS** with an emphasis on low-carbon resources and energy efficiency. Diversification—investing in different asset classes with different risk profiles—is what allows investors to reduce risk (or "volatility") in their investment portfolios. Similarly, diversifying a utility portfolio by including various supply and demand-side resources that behave independently from each other in different future scenarios reduces the portfolio's overall risk.

2. **UTILIZING ROBUST PLANNING PROCESSES** for all utility investment. In many vertically integrated markets and in some organized markets, regulators use "integrated resource planning" (IRP) to oversee utilities' capital investments. IRP is an important tool to ensure that the utilities, regulators and other stakeholders have a common understanding of a full spectrum of utility resource options; that the options are examined in a structured, disciplined way; that demand-side resources get equal consideration alongside supply-side resources; and that the final resource plan is understood by all.

3. **EMPLOYING TRANSPARENT RATEMAKING PRACTICES** that reveal risk. For example, allowing a current return on construction work in progress (CWIP) to enable utilities to finance large projects doesn't actually reduce risk but rather transfers it from the utility to consumers.[13] While analysts and some regulators favor this approach, its use can obscure a project's risk and create a "moral hazard" for utilities to undertake more risky investments. Utility investment in the lowest-cost and lowest-risk resource, energy efficiency, requires regulatory adjustments that may include decoupling utility revenues from sales and performance-based financial incentives.

4. **USING FINANCIAL AND PHYSICAL HEDGES**, including long-term contracts. These allow utilities to lock in a price (e.g., for fuel), thereby avoiding the risk of higher market prices later. But these options must be used carefully since using them can foreclose an opportunity to enjoy lower market prices.

5. **HOLDING UTILITIES ACCOUNTABLE** for their obligations and commitments. This helps to create a consistent, stable regulatory environment, which is highly valued in the marketplace and ensures that agreed-upon resource plans become reality.

6. **OPERATING IN ACTIVE, "LEGISLATIVE" MODE**, continually seeking out and addressing risk. In "judicial mode," a regulator takes in evidence in formal settings and resolves disputes; in contrast, a regulator operating in "legislative mode" proactively seeks to gather all relevant information and to find solutions to future challenges.

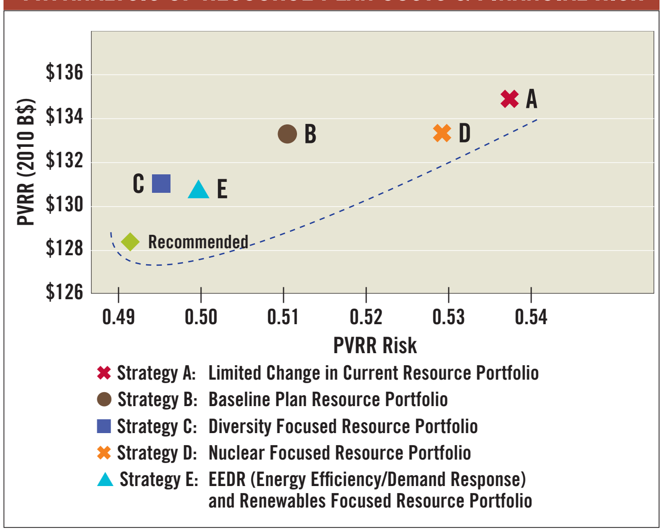
7. **REFORMING AND RE-INVENTING RATEMAKING POLICIES** as appropriate. Today's energy industry faces disruptions similar to those experienced by the telecommunications industry over the past two decades, which led regulators to modernize their tools and experiment with various types of incentive regulation. One area where electricity regulators might profitably question existing practices is rate design; existing pricing structures should be reviewed for the incentives they provide for customers and the outcomes they create for utilities.

13 For example, the use of CWIP financing in Florida could result in Progress Energy customers paying the utility more than $1 billion for a new nuclear plant (the Levy County Nuclear Power Plant) that may never be built. Florida state law prohibits ratepayers from recouping their investment in Levy or other CWIP-financed projects.

Careful planning is the regulator's primary risk management tool. A recently completed IRP by the Tennessee Valley Authority (TVA) illustrates how robust planning enables risk-aware resource choices and avoids higher-cost, higher-risk supply portfolios. TVA considered five resource strategies and subjected each to extensive scenario analysis. **Figure ES-5** shows how these strategies mapped out along an "efficient frontier" according to TVA's analysis of cost and risk.[14] The highest-cost, highest-risk strategies were those that maintained TVA's current resource portfolio[15] or emphasized new nuclear plant construction. The lowest-cost, lowest-risk strategies were the ones that diversified TVA's resource portfolio by increasing TVA's investment in energy efficiency and renewable energy. The TVA analysis is careful and deliberate; analyses by other utilities that reach significantly different thematic conclusions must be scrutinized carefully to examine whether the costs and risks of all resources have been properly evaluated.

Figure ES-5

TVA ANALYSIS OF RESOURCE PLAN COSTS & FINANCIAL RISK



Updating traditional practices will require effort and commitment from regulators and regulatory staff. Is it worth it? This report identifies numerous benefits from practicing "risk-aware regulation":

- **Consumer benefits** from improved regulatory decision-making and risk management, leading to greater utility investment in lower-cost, lower-risk resources;
- **Utility benefits** in the form of a more stable, predictable business environment that enhances long-term planning capabilities;
- **Investor benefits** resulting from lowered threats to utility cost recovery, which simultaneously preserves utility credit quality and capital markets access and keeps financing costs low, benefitting all stakeholders;
- **Systemic regulatory benefits** resulting from expanded transparency, inclusion and sophistication in the regulatory process, thereby strengthening stakeholder relationships, building trust and improving policy maker understanding of energy options—all of which enhances regulators' ability to do their jobs;
- **Broad societal benefits** flowing from a cleaner, smarter, more resilient electricity system.

With two trillion dollars on the line, both the stakes and the potential benefits are high. If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Practicing risk-aware regulation will enable them to avoid expensive mistakes and identify the most important utility investments for realizing the promise of an advanced 21st century electricity system.

Effectively managing risk is not simply achieving the least cost today, but rather is part of a strategy to minimize overall costs over the long term.

14 Tennessee Valley Authority (TVA), *TVA's Environmental and Energy Future* (Knoxville, TN: Tennessee Valley Authority, 2011), 161, http://www.tva.com/environment/reports/irp/pdf/Final_IRP_complete.pdf.

15 As of spring 2010, TVA's generation mix consisted mainly of coal (40 percent), natural gas (25 percent) and nuclear (18 percent) (TVA, 73).

CONCLUSIONS & RECOMMENDATIONS

- **The U.S. electric utility industry has entered what may be the most uncertain, complex and risky period in its history.** Several forces will conspire to make the next two decades especially challenging for electric utilities: large investment requirements, stricter environmental controls, decarbonization, changing energy economics, rapidly evolving technologies and reduced load growth. Succeeding with this investment challenge—building a smarter, cleaner, more resilient electric system for the 21st century at the lowest overall risk and cost—will require commitment, collaboration, shared understanding, transparency and accountability among regulators, policy makers, utilities and a wide range of stakeholders.

- **These challenges call for new utility business models and new regulatory paradigms.** Both regulators and utilities need to evolve beyond historical practice. Today's electricity industry presents challenges that traditional electricity regulation did not anticipate and cannot fully address. Similarly, the constraints and opportunities for electric utilities going forward are very different than they were a century ago, when the traditional (and still predominant) utility business model emerged.

  Regulators must recognize the incentives and biases that attend traditional regulation, and should review and reform their approaches to resource planning, ratemaking and utility cost recovery accordingly. Utilities must endorse regulatory efforts to minimize investment risks on behalf of consumers and utility shareholders. This means promoting an inclusive and transparent planning process, diversifying resource portfolios, supporting forward-looking regulatory policies, continually reevaluating their strategies and shaking off "we've always done it that way" thinking.

- **Avoiding expensive utility investment mistakes will require improved approaches to risk management in the regulatory process.** One of the most important duties of a 21st century electricity regulator is to understand, examine and manage the risk inherent in utility resource selection. Existing regulatory tools often lack the sophistication to do this effectively.

  Higher risk for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both. Our analysis across seven major risk categories reveals that, almost without exception, the riskiest resources—the ones that could cause the most financial harm—are large base load fossil and nuclear plants. It is therefore especially important that regulators and utilities explicitly address and manage risk when considering the development of these resources.

  Regulators practicing "risk-aware regulation" must exhaust lower-risk investment options like energy efficiency before allowing utilities to commit huge sums to higher-risk projects. Regulators should immediately notify regulated utilities of their intention to address risks more directly, and then begin explicitly to include risk assessment in all decisions about utility resource acquisition.

- **More than ever, ratepayer funding is a precious resource.** Large investment requirements coupled with flat or decreasing load growth will mean higher utility rates for consumers. Increased consumer and political resistance to rising electricity bills, and especially to paying for expensive mistakes, leaves much less room for error in resource investment decisions and could pose a threat to utility earnings.

- **Risk shifting is not risk minimization.** Some regulatory practices that are commonly perceived to reduce risk (e.g., construction work in progress financing, or "CWIP") merely transfer risk from the utility to consumers. This risk shifting can inhibit the deployment of attractive lower-cost, lower-risk resources. Regulatory practices that shift risk must be closely scrutinized to see if they actually increase risk—for consumers in the short term, and for utilities and shareholders in the longer term.
- **Investors are more vulnerable than in the past.** During the 1980s, power plant construction cost overruns and findings of utility mismanagement led regulators to disallow more than six percent of utilities' overall capital investment, costing shareholders roughly $19 billion. There will be even less tolerance for errors in the upcoming build cycle and more pressure on regulators to protect consumers. Investors should closely monitor utilities' large capex decisions and consider how the regulatory practice addresses the risk of these investments. Investors should also observe how the business models and resource portfolios of specific utilities are changing, and consider engaging with utility managements on their business strategies going forward.
- **Cost recovery mechanisms currently viewed positively by the investment community including the rating agencies could pose longer-term threats to utilities and investors.** Mechanisms like CWIP provide utilities with the assurance of cost recovery before the outlay is made. This could incentivize utilities to take on higher-risk projects, possibly threatening ultimate cost recovery and deteriorating the utility's regulatory and business environment in the long run.
- **Some successful strategies for managing risk are already evident.** Regulators and utilities should pursue diversification of utility portfolios, adding energy efficiency, demand response, and renewable energy resources to the portfolio mix. Including a mix of supply and demand-side resources, distributed and centralized resources, and fossil and non-fossil generation provides important risk management benefits to resource portfolios because each type of resource behaves independently from the others in different future scenarios. In the other direction, failing to diversify resources, "betting the farm" on a narrow set of large resources, and ignoring potentially disruptive future scenarios is asking for trouble.

Including a mix of supply and demand-side resources, distributed and centralized resources, and fossil and non-fossil generation provides important risk management benefits to resource portfolios because each type of resource behaves independently from the others in different future scenarios.

- **Regulators have important tools at their disposal.** Careful planning is the regulator's primary tool for risk mitigation. This is true for regulators in both vertically-integrated and restructured electricity markets. Effective resource planning considers a wide variety of resources, examines possible future scenarios and considers the risk of various portfolios. Regulators should employ transparent ratemaking practices that reveal and do not obscure the level of risk inherent in a resource choice; they should selectively apply financial and physical hedges, including long-term contracts. Importantly, they must hold utilities accountable for their obligations and commitments.

1. CONTEXT:

INCREASING CAPITAL INVESTMENT BY U.S. ELECTRIC UTILITIES AMID HISTORIC UNCERTAINTY & RISK

U.S. ELECTRIC UTILITIES ARE FACING A SET OF CHALLENGES UNPARALLELED IN THE INDUSTRY'S HISTORY, PROVIDING MANY REASONS TO CONCLUDE THAT THE TRADITIONAL PRACTICES OF UTILITIES AND THEIR REGULATORS MUST BE UPDATED TO ADD A SHARPER FOCUS ON RISK MANAGEMENT IN THE REGULATORY PROCESS.

Consider the forces acting on the electricity sector in 2012:

- an aging generation fleet;
- infrastructure upgrades to the distribution system;
- increasingly stringent environmental regulation limiting pollutants and greenhouse gases;[16]
- disruptive changes in the economics of coal and natural gas;
- new transmission investments;
- rapidly evolving smart grid technologies enabling greater customer control and choice;
- increased policy maker emphasis on demand-side resources requiring new regulatory approaches and utility business models;
- competition from growth in distributed generation;
- slow demand growth due to protracted economic recovery and high unemployment;
- tight credit in a difficult economy and substantially weakened industry financial metrics and credit ratings.

In a recent book, Peter Fox-Penner, principal and chairman emeritus of the Brattle Group, concluded that the sum of these forces is leading to a "second revolution" in the electric power industry.[17] Navigant Consulting has observed that "the changes underway in the 21st century electric power sector create a level and complexity of risks that is perhaps unprecedented in the industry's history."[18]

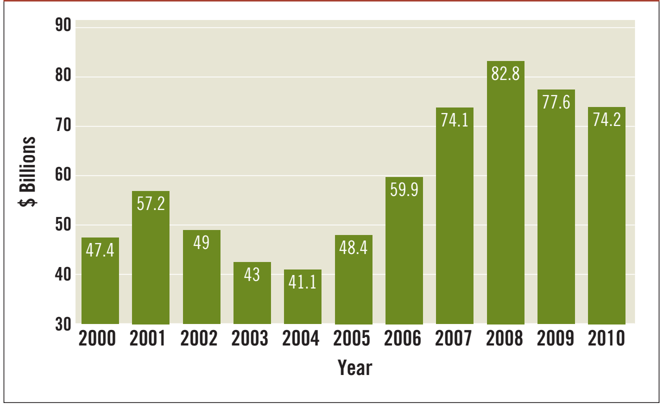
THE INVESTMENT CHALLENGE

The United States electric utility industry is a network of approximately 3,300 investor-owned utilities (IOUs), cooperative associations and government entities. In addition, about 1,100 independent power producers sell power to utilities, either under contract or through auction markets. The net asset value of the plant in service for all U.S. electric utilities in 2010 was about $1.1 trillion, broken down as $765 billion for IOUs, about $200 billion for municipal (publicly-owned) utilities (or "munis"), and $112 billion for rural electric cooperatives (or "co-ops").[19]

IOUs therefore constitute the largest segment of the U.S. electric power industry, serving roughly 70 percent of the U.S. population. **Figure 1** illustrates IOUs' capital expenditures from 2000-2010 and captures the start of the current "build cycle," beginning in 2006.[20] Between 2006 and 2010, capital spending by IOUs—for generation, transmission and distribution systems—was about 10 percent of the firms' net plant in service.

Figure 1

CAPITAL EXPENDITURES BY U.S. INVESTOR-OWNED UTILITIES, 2000-2010



16 See footnote 2.

17 Peter Fox-Penner, *Smart Power* (Washington DC: Island Press, 2010). The "first revolution" was triggered by George Westinghouse, Thomas Edison, Nicola Tesla, Samuel Insull and others more than a century ago.

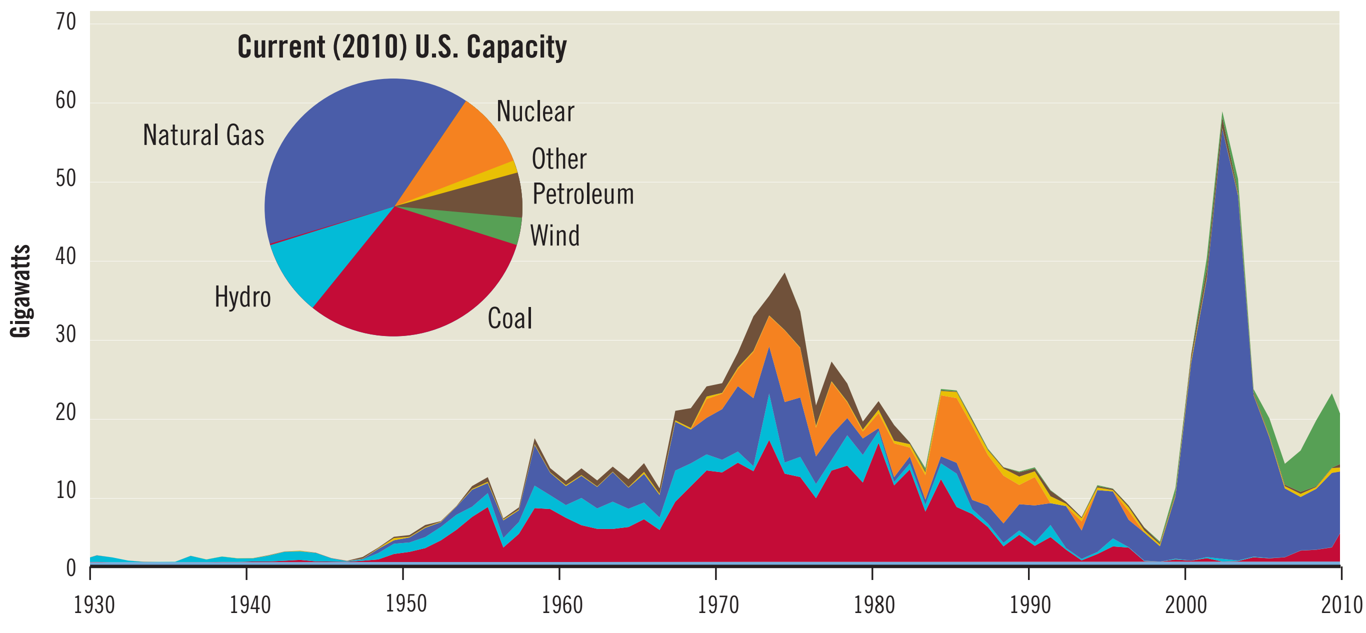
18 Small and Frantzis, *The 21st Century Electric Utility*, 28.

19 See U.S. Energy Information Administration, "Electric Power Industry Overview 2007," http://www.eia.gov/cneaf/electricity/page/prim2/toc2.html; National Rural Electric Cooperative Association, "Co-op Facts and Figures," http://www.nreca.coop/members/Co-opFacts/Pages/default.aspx; Edison Electric Institute, "Industry Data," http://www.eei.org/whatwedo/DataAnalysis/IndustryData/Pages/default.aspx. Note that these numbers do not include investment by non-utility generators.

20 Edison Electric Institute, *2010 Financial Review*, 18.

Figure 2

U.S. ELECTRIC GENERATING CAPACITY BY IN-SERVICE YEAR AND FUEL TYPE



In 2008, the Brattle Group projected that the collected U.S. electric utility industry—IOUs, munis, and co-ops—would need to invest capital at historic levels between 2010 and 2030 to replace aging infrastructure, deploy new technologies, and meet future consumer needs and government policy requirements. In all, Brattle predicted that total industry-wide capital expenditures from 2010 to 2030 would amount to between \$1.5 trillion and \$2.0 trillion.[21] Assuming that the U.S. implements a policy limiting greenhouse gas emissions, the collected utility industry may be expected to invest at roughly the same elevated annual rate as in the 2006-2010 period *each year for 20 years.*

If the U.S. utility industry adds \$100 billion each year between 2010 and 2030, the net value of utility plant in service will grow from today's \$1.1 trillion to more than \$2.0 trillion—a doubling of net invested capital.

If the U.S. utility industry adds \$100 billion each year between 2010 and 2030, the net value of utility plant in service will grow from today's \$1.1 trillion to more than \$2.0 trillion—a doubling of net invested capital. This growth is considerably faster than the country has seen in many decades.

To understand the seriousness of the investment challenge facing the industry, consider the age of the existing generation fleet. About 70 percent of U.S. electric generating capacity is at least 30 years old (**Figure 2**).[22] Much of this older capacity is coal-based generation subject to significant pressure from the Clean Air Act (CAA) because of its emissions of traditional pollutants such as nitrous oxides, sulfur dioxides, mercury and particulates. Moreover, following a landmark Supreme Court ruling, the U.S. Environmental Protection Agency (EPA) is beginning to regulate as pollutants carbon dioxide and other greenhouse gas emissions from power plants.[23] These regulations will put even more pressure on coal plants, which produce the most greenhouse gas emissions of any electric generating technology. The nuclear capacity of the U.S., approximately 100,000 megawatts, was built mainly in the 1970s and 80s, with original licenses of 40 years. While the lives of many nuclear plants are being extended with additional investment, some of these plants will face retirement within the next two decades.

21 Chupka et al., *Transforming America's Power Industry*, vi. Brattle's investment estimates apply to the entire U.S. electric utility industry, including IOUs, electric cooperatives and government-owned utilities. The range in Brattle's investment estimate is due to its varying assumptions about U.S. climate policy enactment.

22 U.S. Energy Information Administration, "Today in Energy: Age of electric power generators varies widely," June 16, 2011, http://www.eia.gov/todayinenergy/detail.cfm?id=1830.

23 U.S. Supreme Court, *Massachusetts v. Environmental Protection Agency,* 549 U.S. 497 (2007), http://www.supremecourt.gov/opinions/06pdf/05-1120.pdf.

Figure 3

PROJECTED GENERATION CAPEX BY REGION

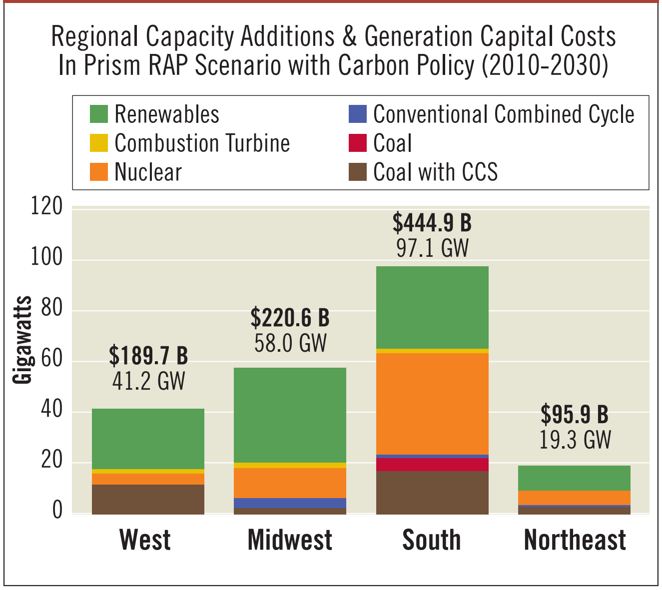


Figure 4

PROJECTED CAPACITY ADDITIONS BY STATE & AS A PERCENTAGE OF 2010 GENERATING CAPACITY

State	Predicted Capacity Additions (MW), 2010-2030[25]	Predicted Additions as a Percentage of 2010 Generating Capacity[26]
Texas	23,400	22%
Florida	12,200	21%
Illinois	11,000	25%
Ohio	8,500	26%
Pennsylvania	6,300	14%
New York	5,400	14%
Colorado	2,500	18%

Figure 3 shows the Brattle Group's investment projections for new generating capacity for different U.S. regions,[24] while **Figure 4** predicts capacity additions for selected U.S. states. Importantly, the Brattle Group noted that some of this investment in new power plants could be avoided if regulators and utilities pursued maximum levels of energy efficiency.

DRIVERS OF UTILITY INVESTMENT

Technological change, market pressures and policy imperatives are driving these historic levels of utility investment. As we will see, these same forces are interacting to create unprecedented uncertainty, risk and complexity for utilities and regulators.

Here are eight factors driving the large investment requirements:

1. **THE NEED TO REPLACE AGING GENERATING UNITS.** As mentioned earlier, the average U.S. generating plant is more than 30 years old. Many plants, including base load coal and nuclear plants, are reaching the end of their lives, necessitating either life-extending investments or replacement.

2. **ENVIRONMENTAL REQUIREMENTS.** Today's Clean Air Act (CAA) traces its lineage to a series of federal laws dating back to 1955. Until recent years, the CAA has enjoyed broad bipartisan support as it steadily tightened controls on emissions from U.S. electric power plants. These actions were taken to achieve science-based health improvements for people and the human habitat. While the current set of EPA rules enforcing the CAA has elicited political resistance, it is unlikely that the five-decade long movement in the United States to reduce acid rain, smog, ground ozone, particulates and mercury, among other toxic pollutants, will be derailed. Owners of many fossil-fueled plants will be forced to decide whether to make significant capital investments to clean up emissions and manage available water, or shutter the plants. Since the capacity is needed to serve consumers' demand for power (or "load"), these clean air and clean water policies will stimulate the need for new construction.

24 Chupka et al., *Transforming America's Power Industry*, x. Brattle's Prism RAP Scenario "assumes there is a new federal policy to constrain carbon emissions, and captures the cost of EPRI's [Electric Power Research Institute] Prism Analysis projections for generation investments (nuclear, advanced coal, renewables, etc.) that will reduce the growth in carbon emissions. This scenario further assumes the implementation of RAP [realistically achievable potential] EE/DR programs" (ibid., vi). Brattle used EPRI's original Prism analysis, published in September 2007; that document and subsequent updates are available online at http://my.epri.com/portal/server.pt?open=512&objID=216&&PageID=229721&mode=2.

25 State capacity addition predictions are based on Brattle's regional projections and assume that new capital expenditures will be made in proportion to existing investment levels.

26 State generating capacity data: U.S. Energy Information Administration, "State Electricity Profiles," January 30, 2012, http://www.eia.gov/electricity/state/. Percentage is rounded to the nearest whole number.

3 **NEW TRANSMISSION LINES AND UPGRADES.** Utility investment in transmission facilities slowed significantly from 1975 to 1998.[27] In recent years, especially after the creation of deregulated generation markets in about half of the U.S., it has become clear that the transmission deficit will have to be filled. Adding to the need for more transmission investment is the construction of wind, solar and geothermal generation resources, far from customers in areas with little or no existing generation or transmission. Regional transmission planning groups have formed across the country to coordinate the expected push for new transmission capacity.

4 **NETWORK MODERNIZATION/SMART GRID.** The internet is coming to the electric power industry. From synchrophasors on the transmission system (which enable system-wide data measurement in real time), to automated substations; from smart meters, smart appliances, to new customer web-based energy management, investments to "smarten" the grid are fundamentally changing the way electricity is delivered and used. While much of today's activity results from "push" by utilities and regulators, many observers think a "pull" will evolve as consumers engage more fully in managing their own energy use. Additionally, "hardening" the grid against disasters and to enhance national security will drive further investment in distribution infrastructure.

5 **HIGHER PRICES FOR CONSTRUCTION MATERIALS.** Concrete and steel are now priced in a world market. The demand from developing nations is pushing up the cost of materials needed to build power plants and transmission and distribution facilities.

6 **DEMAND GROWTH.** Overall U.S. demand for electric power has slowed with the recent economic recession and is projected to grow minimally in the intermediate term (though some areas, like the U.S. Southwest and Southeast, still project moderate growth). Further, the expected shift toward electric vehicles has the potential to reshape utility load curves, expanding the amount of energy needed in off-peak hours.

7 **DEPLOYING NEW TECHNOLOGIES AND SUPPORTING R&D.** To meet future environmental requirements, especially steep reductions of greenhouse gas emissions by 2050, utilities will need to develop and deploy new technologies at many points in the grid. Either directly or indirectly, utilities will be involved in funding for R&D on carbon capture and storage, new renewable and efficiency technologies, and electric storage.

8 **NATURAL GAS PRICE OUTLOOK.** Natural gas prices have fallen sharply as estimates of U.S. natural gas reserves jumped with the development of drilling technologies that can economically recover gas from shale formations. Longer-term price estimates have also dropped, inducing many utilities to consider replacing aging coal units with new gas-fired units. But in January 2012, the U.S. Energy Information Administration (EIA) sharply revised downward its estimates of U.S. shale gas reserves by more than 40 percent and its estimates of shale gas from the Marcellus region by two-thirds.[28] Reduced long-term supplies and a significant commitment to natural gas for new electric generation could obviously lead to upward pressure on natural gas prices.

FINANCIAL IMPLICATIONS

The credit quality and financial flexibility of U.S. investor-owned electric utilities has declined over the past 40 years, and especially over the last decade (**Figure 5, p. 18**).[29] The industry's financial position today is materially weaker than it was during the last major "build cycle" that was led by vertically-integrated utilities, in the 1970s and 80s. Then the vast majority of IOUs had credit ratings of "A" or higher; today the average credit rating has fallen to "BBB."

While it is rare for utilities to experience multiple notch downgrades in a short period of time, the heightened event risk inherent in the approaching sizable capital spending cycle could cause the rating agencies to pursue more aggressive rating actions.

This erosion of credit quality is mainly the result of intentional decisions by regulators and utility managements, who determined that maintaining an "A" or "AA" balance sheet wasn't worth the additional cost.[30] And while there isn't reason to believe that most utilities' capital markets access will become significantly constrained in the near future, the fact remains that more than a quarter of companies in the sector are now one notch above non-investment grade status (also called "Non-IG," "high yield" or "junk"), and nearly half of the companies in the sector are rated only two or three notches above this threshold.[31] While it is rare for utilities to experience multiple notch downgrades in a short period of time, the heightened event risk inherent in the approaching sizable capital spending cycle could cause the rating agencies to pursue more aggressive rating actions. Dropping below

27 Edison Electric Institute, *EEI Survey of Transmission Investment* (Washington DC: Edison Electric Institute, 2005), 3, http://www.eei.org/ourissues/ElectricityTransmission/Documents/Trans_Survey_Web.pdf.

28 U.S. Energy Information Administration, *AEO2012 Early Release Overview* (Washington DC: U.S. Energy Information Administration, 2012), 9, http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2012).pdf.

29 Source: Standard & Poor's Ratings Service.

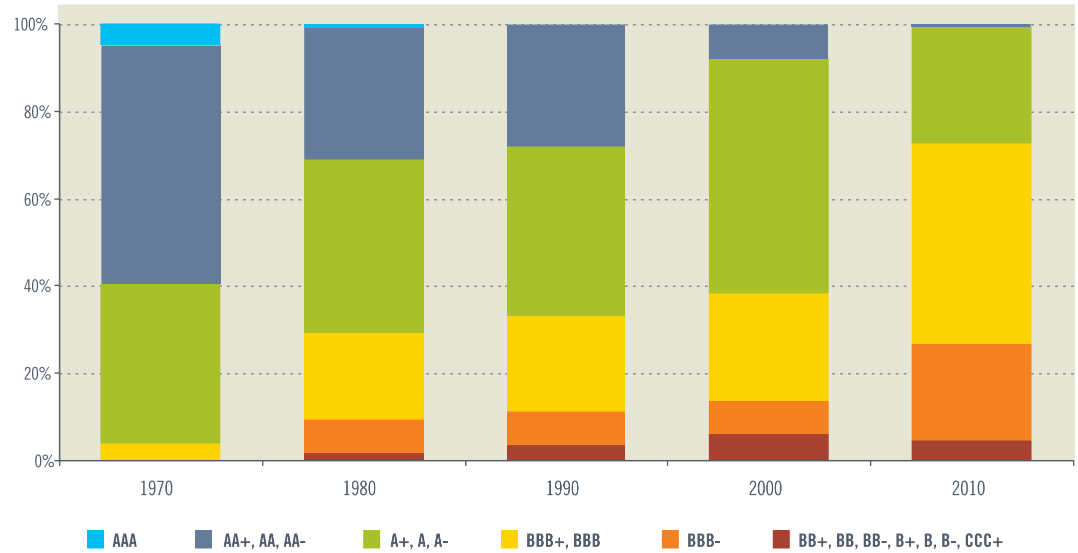
30 The difference in the interest rate on an "A" rated utility and BBB is on average over time rarely more than 100 basis points. By contrast, equity financing typically costs a utility at least 200 basis points more than debt financing.

31 Companies in the sector include IOUs, utility holding companies and non-regulated affiliates.

Figure 5

U.S. ELECTRIC IOUs CREDIT RATINGS HISTORY, 1970 – 2010

S&P Credit Ratings Distribution, U.S. Shareholder-Owned Electric Utilities



investment grade (or "IG") triggers a marked rise in interest rates for debt issuers and a marked drop in demand from institutional investors, who are largely prohibited from investing in junk bonds under the investment criteria set by their boards.

According to a Standard & Poor's analyst, utilities' capital expenditure programs will invariably cause them to become increasingly cash flow negative, pressuring company balance sheets, financial metrics and credit ratings: "In other words, utilities will be entering the capital markets for substantial amounts of both debt and equity to support their infrastructure investments as operating cash flows will not come close to satisfying these infrastructure needs."[32] Specific utilities that S&P has identified as particularly challenged are companies—such as Ameren, Dominion, FirstEnergy, and PPL—that have both regulated and merchant generation businesses and must rely on market pricing to recover environmental capital expenditures for their merchant fleets.[33]

Appendix 1 of this report presents an overview of utility finance.

While the growth of rate base presents an earnings opportunity for regulated utilities and their investors, the corresponding increase in customer bills could greatly exacerbate the political and regulatory risks that threaten utilities' cost recovery.

CUSTOMER IMPACTS

The surge in IOU capital investment will translate directly into higher electric rates paid by consumers. Increased capital investment means higher annual depreciation expenses as firms seek to recover their investment. Greater levels of investment mean higher revenue requirements calculated to yield a return on the investment. And since electric sales may not grow much or at all during the coming two decades, it is likely that unit prices for electricity will rise sharply.

While the growth of rate base presents an earnings opportunity for regulated utilities and their investors, the corresponding increase in customer bills could greatly exacerbate the political and regulatory risks that threaten utilities' cost recovery. The rating agency Moody's Investors Service has noted that "consumer tolerance to rising rates is a primary concern"[34] and has identified political and regulatory risks as key longer-term challenges facing the sector.[35]

Further, Moody's anticipates an "inflection point" where consumers revolt as electricity bills consume a greater share of disposable income (**Figure 6, p. 19**),[36] pressuring legislators and regulators to withhold from utilities the recovery of even prudently incurred expenses.

32 Cortright, "Testimony."

33 Standard & Poor's, *The Top 10 Investor Questions for U.S. Regulated Electric Utilities in 2012* (New York: Standard & Poor's, 2012).

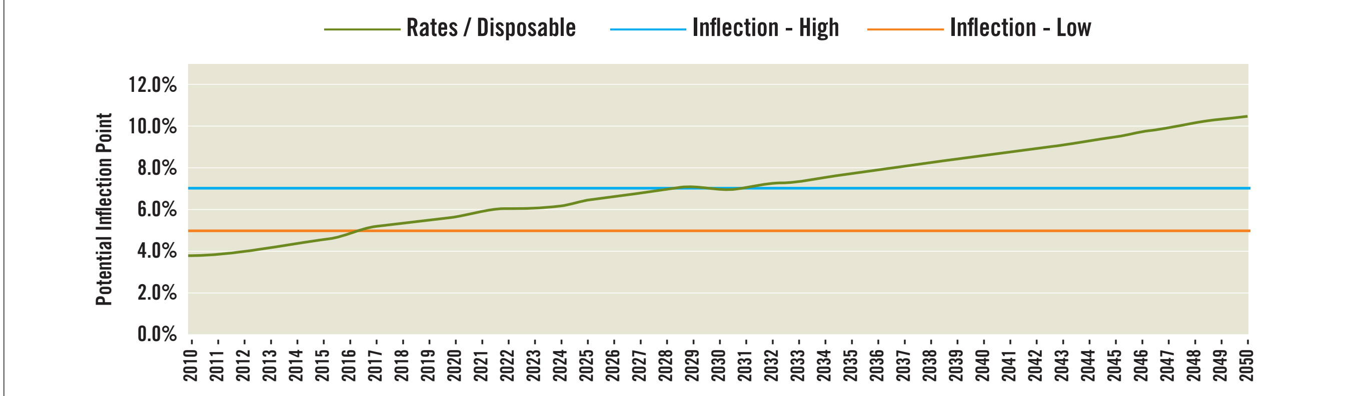
34 Moody's Investors Service, *Industry Outlook: Annual Outlook* (New York: Moody's Investors Service, 2011).

35 Moody's Investors Service, *Industry Outlook: Annual Outlook* (New York: Moody's Investors Service, 2010).

36 Moody's, *Special Comment: The 21st Century Electric Utility*, 12.

Figure 6

MOODY'S PROJECTED "INFLECTION POINT" OF CONSUMER INTOLERANCE FOR RISING ELECTRICITY BILLS



Source: Moody's

THE IMPORTANCE OF REGULATORS

With this background, the challenge becomes clear: how to ensure that the large level of capital invested by utilities over the next two decades is deployed wisely? How to give U.S. ratepayers, taxpayers and investors the assurance that $2 trillion will be spent in the best manner possible? There are two parts to the answer: *effective regulators* and the *right incentives for utilities*.

If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Each regulator will, on average, vote to approve more than $6.5 billion of utility capital investment during his or her term.[37] It is essential that regulators understand the risks involved in resource selection, correct for the biases facing utility regulation and keep in mind the impact their decisions will have on consumers and society.

Are U.S. regulatory institutions prepared? Consumers, lawmakers and the financial markets are counting on it. The authors are confident that well-informed, focused state regulators are up to the task. But energy regulation in the coming decades will be quite different from much of its history. The 21st century regulator must be willing to look outside the boundaries established by regulatory tradition. Effective regulators must be informed, active, consistent, curious and often courageous.

This report focuses on techniques to address the risk associated with utility resource selection. It provides regulators with some tools needed to understand, identify and minimize the risks inherent in the industry's investment challenge. In short, we hope to help regulators become more "risk-aware."

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37 In 2012, the median number of years served by a state regulator was 3.7 years; see Janice A. Beecher, Ph.D., *IPU Research Note: Commissioner Demographics 2012* (East Lansing, MI: Michigan State University, 2012), http://ipu.msu.edu/research/pdfs/IPU-Commissioner-Demographics-2012.pdf.

2. CHALLENGES

TO EFFECTIVE REGULATION

THE CHALLENGE FOR U.S. ELECTRIC UTILITIES IS TO RAISE, SPEND AND RECOVER A HISTORIC AMOUNT OF CAPITAL DURING A PERIOD OF UNPRECEDENTED UNCERTAINTY. THE CHALLENGE FOR STATE REGULATORS IS TO DO EVERYTHING POSSIBLE TO ENSURE THAT UTILITIES' INVESTMENTS ARE MADE WISELY. TO DO THIS EFFECTIVELY, REGULATORS WILL NEED TO BE ESPECIALLY ATTENTIVE TO TWO AREAS: IDENTIFYING AND ADDRESSING RISK, AND OVERCOMING REGULATORY BIASES. THIS SECTION DISCUSSES RISK AND BIAS IN MORE DETAIL.

RISK INHERENT IN UTILITY RESOURCE SELECTION

Risk arises when there is potential harm from an adverse event that can occur with some degree of probability. Risk accumulates from multiple sources. In mathematical terms:

Risk $= \sum_i Event_i \times (Probability\ of\ Event_i)$

for a situation in which a set of independent events will cause a loss with some probability. In English, this means that risk is the sum of each possible loss times the probability of that loss, assuming the events are independent of each other. If a financial instrument valued at $100 million would be worth $60 million in bankruptcy, and the probability of bankruptcy is 2 percent, then the bankruptcy risk associated with that instrument is said to be ($100 million - $60 million) x 2%, or $800,000. Thus, risk is the *expected value of a potential loss*. There is an obvious tie to insurance premiums; leaving aside transaction costs and the time value of money, an investor would be willing to pay up to $800,000 to insure against the potential bankruptcy loss just described.

Higher risk for a resource or portfolio means a larger expected value of a potential loss. In other words, higher risk means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Uncertainty is similar to risk in that it describes a situation where a deviation from the expected can occur, but it differs in two respects. First, the probability of the unexpected event cannot feasibly be determined with any precision. Consider the potential of much higher costs for natural gas used as a generation resource for an electric utility. Such an outcome is certainly possible (and perhaps even likely, given the potential for an increased rate of construction of new natural gas generation). But the likelihood and scope of such a change would be difficult to assess in terms of mathematical probabilities. Second, unlike risk, uncertainty can result in

The Historical Basis for Utility Regulation

Utilities aren't like other private sector businesses. Their services are essential in today's world, and society expects utilities to set up costly infrastructure networks supported by revenue from electric rates and to serve everyone without discrimination. Because of their special attributes, we say that investor-owned utilities are private companies that are "affected with the public interest." Indeed, this is often the statutory definition of utilities in state law.

Utility infrastructure networks include very long-lived assets. Power plants and transmission lines are designed to last decades; some U.S. transmission facilities are approaching 100 years old. The high cost of market entry makes competition impractical, uneconomic or impossible in many sectors of these markets. And because society requires universal service, it made economic sense to grant monopoly status to the owners of these essential facilities and then to regulate them.

State regulatory utility commissioners began administering a system of oversight for utilities at about the turn of the 20th century, filling a role that had previously been accorded to state legislatures. Regulatory commissions were tasked with creating a stable business environment for investment while assuring that customers would be treated "justly and reasonably" by monopoly utilities. Then as now, consumers wanted good utility services and didn't want to pay too much for them. Rules for accounting were supplemented by regulatory expectations, which were then followed by a body of precedents associated with cost recovery.

Because the sector's complexity and risks have evolved considerably since many regulatory precedents were established, today's regulators are well-advised to "think outside the box" and consider reforming past precedent where appropriate. The last section of this report, "Practicing Risk-Aware Regulation," contains specific ideas and recommendations in this regard.

Figure 7

VARIETIES OF RISK FOR UTILITY RESOURCE INVESTMENT	
Cost-related	***Time-related***
Construction costs higher than anticipated	Construction delays occur
Availability and cost of capital underestimated	Competitive pressures; market changes
Operation costs higher than anticipated	Environmental rules change
Fuel costs exceed original estimates, or alternative fuel costs drop	Load grows less than expected; excess capacity
Investment so large that it threatens a firm	Better supply options materialize
Imprudent management practices occur	Catastrophic loss of plant occurs
Resource constraints (e.g., water)	Auxiliary resources (e.g., transmission) delayed
Rate shock: regulators won't put costs into rates	Other government policy and fiscal changes

either upside or downside changes. As we will see later, uncertainty should be identified, modeled and treated much like risk when considering utility resource selection. In this report we will focus on risk and the negative aspect of uncertainty, and we will simplify by using the term "risk" to apply to both concepts.

The risks associated with utility resource selection are many and varied and arise from many possible events, as shown in **Figure 7**. There are several ways to classify these risks. One helpful distinction is made between cost-related risks and time-related risks.

Cost risks reflect the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations. Construction costs for a project can increase between regulatory approval and project completion. Transmission projects are notorious for this phenomenon due to unexpected obstacles in siting, or to unexpected changes in raw material costs.

Costs can change unexpectedly at any time. For example, a catastrophic equipment failure or the adoption of a new standard for pollution control could present unforeseen costs that a utility may not be willing to pay to keep an asset operating. Planned-for cost recovery can be disrupted by changes in costs for which regulators are unwilling to burden customers, or for other reasons. If an asset becomes obsolete, useless or uneconomic before the end of its predicted economic life, a regulator could find that it is no longer "used and useful" to consumers and remove it from the utility rate base. In these ways, decisions made by utilities and their regulators may turn out to be much more costly than initially expected. For this reason, it is especially important that regulators and utilities consider a full range of options and resources at the time a major investment decision is made.

Time risks reflect the possibility that circumstances will change over the life of the investment and materially affect both the cost of the investment and the degree to which it benefits consumers. Sometimes this risk can manifest itself even between the time a utility makes a decision and the time approval is sought. For example, anticipated load growth may not materialize, so that a planned generation resource is not needed, at least not now.

Time risks also reflect the fact that, for some investments, some essential condition may not occur on a schedule necessary for the investment to be approved and constructed. Consider the dilemma of the developer who wishes to build a low cost wind farm in an area with weak electric transmission. The wind project might require three to four years to build, but the transmission capacity needed to move the power to market may take five to seven years to build—*if* the development goes relatively smoothly. Investors may forego the wind farm due to uncertainty that the transmission will be built, while at the same time the transmission might not be built because, without the wind farm, it is simply too speculative.

Decisions made by utilities and their regulators may turn out to be much more costly than initially expected. For this reason, it is especially important that regulators and utilities consider a full range of options and resources at the time a major investment decision is made.

In the power sector, investments are so long-lived that time can be measured in generations. Generally speaking, regulators consider it most fair if the generation of consumers that uses an asset is the same one that pays for the asset. Burdening customers before or after an asset is useful is often seen as violating the "just and reasonable" standard. The challenge to the utility, therefore, is to fit cost recovery for an asset into the timeframe in which it is used. Otherwise, the utility may bear the risk that regulators or consumers push back on assuming responsibility for the cost.

Perspectives on Risk

Risk means different things to different stakeholders. For example:

- For **utility management**, risks are a threat to the company's financial health, its growth, even its existence; a threat to the firm's competitiveness, to the firm's image, and to its legacy.
- For **customers**, risk threatens household disposable income, the profitability of businesses, the quality of energy service, and even comfort and entertainment.
- **Investors** focus on the safety of the income, value of the investment (stock or bond holders), or performance of the contract (counterparties). In addition, investors value utility investments based on their expectations of performance.
- **Employees** are uniquely connected to the utility. Their employment, safety and welfare is directly related to their company's ability to succeed and to avoid financial catastrophes.
- **Society generally** has expectations for utilities ranging from providing reliable, universal service, to aiding in economic development, to achieving satisfactory environmental and safety performance. Risk threatens these goals.

ELECTRICITY MARKET STRUCTURE AND RISK

Much has changed since non-utility power producers led the most recent industry build cycle in the 1990s and early 2000s. To begin with, financial reforms from Sarbanes-Oxley legislation, other "Enron fixes," and now the Dodd-Frank Act have substantially changed some accounting and corporate disclosure rules. Investors now receive more detailed and transparent information about asset value (which is "marked to market") and possible risks in contracts with counter-parties.

These changes, which protect investors, may have the associated effect of discouraging investments if cumulative risks are judged to be outsized for the circumstances. This is especially relevant for markets served by the competitive generation system that now supplies power to about half of U.S. consumers. It is unclear whether independent generators have the tolerance to take on large, risky investments; experience indicates that there is a frontier beyond which these companies and their backers may not go.

This dynamic could raise important questions for regulators in restructured markets, who need to be aware of the degree to which investment options might be limited by these concerns. In vertically-integrated markets, regulators' concern should be not to expose utilities, customers and investors to undue risk by approving large projects that informed market players would not pursue in the absence of regulatory approval.

One potentially risky but necessary area of investment is in low carbon generation technologies. The U.S. power sector, which has embraced generation competition, is required to develop these technologies. Some promising technologies—including coal-fired generation with carbon capture and storage or sequestration (CCS), advanced nuclear power technologies and offshore wind—have not reached a commercial stage or become available at a commercial price.

Risks requiring special attention are those associated with investments that "bet the company" on their success. Gigawatt-sized investments in any generation technology may trigger this concern, as can a thousand-mile extra high voltage transmission line. Any investment measured in billions of dollars can be proportionately out of scale with what a utility can endure if things go awry. Regulators should avoid a situation where the only choices left are a utility bankruptcy or a waiving of regulatory principles on prudence and cost recovery in order to save the utility, placing a necessary but unreasonable cost burden on consumers.

REGULATORS, RATING AGENCIES AND RISK

Investor-owned utilities sometimes attempt to get out in front of the event risk inherent in large investment projects by seeking pre-approval or automatic rate increase mechanisms. As discussed later, these approaches don't actually reduce risk, but instead shift it to consumers. This may give companies and investors a false sense of security and induce them to take on excessive risk. In the long run this could prove problematic for investors; large projects can trigger correspondingly large rate increases years later, when regulators may not be as invested in the initial deal or as willing to burden consumers with the full rate increase.

Given the influence of regulators on the operations and finances of IOUs, ratings agencies and investors closely monitor the interactions between utility executives and regulators. Constructive relationships between management and regulators are viewed as credit positive; less-than-constructive relationships, which can result from regulators' concerns about the competence or integrity of utility management, are seen as a credit negative and harmful to a utility's business prospects.

Analysts define a constructive regulatory climate as one that is likely to produce stable, predictable regulatory outcomes over time. "Constructive," then, refers as much to the quality of regulatory decision-making as it does to the financial reward for the utility. Regulatory decisions that seem overly generous to utilities could raise red flags for analysts, since these decisions could draw fire and destabilize the regulatory climate. Analysts may also become concerned about the credit quality of a company if the state regulatory process appears to become unduly politicized.

While they intend only to observe and report, ratings agencies can exert a discipline on utility managements not unlike that imposed more formally by regulators. For example, ratings agencies can reveal to utility managements the range of factors they should consider when formulating an investment strategy, thereby influencing utility decision-making. Both regulators and ratings agencies set long-term standards and expectations that utilities are wise to mind; both can provide utilities with feedback that would discourage one investment strategy or another.

Since ratings reflect the issuer's perceived ability to repay investors over time, the ratings agencies look negatively on anything that increases event risk. The larger an undertaking (e.g., large conventional generation investments), the larger the fallout if an unforeseen event undermines the project. The pressure to maintain healthy financial metrics may, in practice, serve to limit utilities' capital expenditure programs and thus the size of rate increase requests to regulators.

TAKEAWAYS ABOUT RISK

Here are three observations about risk that should be stressed:

1. RISK CANNOT BE ELIMINATED—BUT IT CAN BE MANAGED AND MINIMIZED. Because risks are defined in terms of probabilities, it is (by definition) probable that some risk materializes. In utility resource selection, this means that risk will eventually find its way into costs and then into prices for electricity. Thus, taking on risk is inevitable, and risk will translate into consumer or investor costs—into dollars—sooner or later. Later in this report, we present recommendations to enable regulators to practice their trade in a "risk-aware" manner—incorporating the notion of risk into every decision.

2. IT IS UNLIKELY THAT CONSUMERS WILL BEAR THE FULL COST OF POOR UTILITY RESOURCE INVESTMENT DECISIONS. Put another way, it is likely that utility investors (specifically shareholders) will be more exposed to losses resulting from poor utility investments than in years past. In utility regulation, risk is shared between investors and customers in a complex manner. To begin, the existence of regulation and a group of customers who depend on utility service is what makes investors willing to lend utilities massive amounts of money (since most customers have few if any choices and must pay for utility service). But the actualization of a risk, a loss, may be apportioned by regulators to utility investors, utility consumers, or a combination of both. The very large amount of capital investment that's being contemplated and the resulting upward pressure on electricity rates will make it very unappealing (or simply untenable) for regulators to make ratepayers pay for the full cost of utility mistakes.

3. IGNORING RISK IS NOT A VIABLE STRATEGY. Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate. In utility regulation, perhaps more so than anywhere else, making no choice is itself making a choice. Following a practice just because "it's always been done that way," instead of making a fresh assessment of risk and attempting to limit that risk, is asking for trouble.

NATURAL BIASES AFFECTING UTILITY REGULATION

Notwithstanding economic theory, we must admit that utilities are not perfectly rational actors and that their regulation is not textbook-perfect, either. Utility regulation faces several built-in biases, which one can think of as headwinds against which regulation must sail. For example, under traditional cost-of-service regulation, a considerable portion of fixed costs (i.e., investment in rate base) is often recovered through variable charges to consumers. In this circumstance, one would expect utilities to have a bias toward promoting sales of the product once rates are established—even if increasing sales might result in increased financial, reliability, or environmental risks and mean the inefficient use of consumer dollars.

Here are five natural biases that effective utility regulation must acknowledge and correct for:

- **Information asymmetry.** Regulators are typically handicapped by not having the same information that is available to the regulated companies. This becomes especially significant for the utility planning process, where regulators need to know the full range of potential options for meeting electric demand in future periods. In the same vein, regulators do not normally have adequate information to assess market risks. These are the considerations of CFOs and boardrooms, and not routinely available to regulators. Finally, operating utilities often exist in a holding company with affiliated interests. The regulator does not have insight into the interplay of the parent and subsidiary company—the role played by the utility in the context of the holding company.
- **The Averch-Johnson effect.** A second bias is recognized in the economic literature as the tendency of utilities to over-invest in capital compared to labor. This effect is known by the name of the economists who first identified the bias: the Averch-Johnson effect (or simply the "A-J effect"). The short form of the A-J effect is that permitting

a rate of return on investment will have the predictable effect of encouraging more investment than is optimal. This can manifest itself in the "build versus buy" decisions of integrated utilities and is often cited as a reason utilities might "gold plate" their assets. This effect can also be observed in the "invest versus conserve" decisions that utilities face. Under traditional regulatory rules, most utilities do not naturally turn toward energy efficiency investment, even though such investments are usually least cost for customers.

- **The throughput incentive.** A third bias that can be observed with utilities is the bias for throughput—selling more electricity. This is undoubtedly grounded in the vision that most utilities have traditionally had for themselves: providers of electricity. Importantly, the regulatory apparatus in most states reinforces the motivation to sell more electricity: a utility's short-run profitability and its ability to cover fixed costs is directly related to the utility's level of sales. The price of the marginal unit of electricity often recovers more than marginal costs, so utilities make more if they sell more. Only in recent years has the concept of an energy services provider developed in which the utility provides or enables energy efficiency, in addition to providing energy.
- **Rent-seeking.** A fourth bias often cited in the literature is "rent seeking," where the regulated company attempts to use the regulatory or legislative processes as a means of increasing profitability (rather than improving its own operational efficiency or competitive position). This can occur when firms use law or regulation to protect markets that should be open to competition, or to impose costs on competitors.
- **"Bigger-is-better"** syndrome. Another bias, related to the Averch-Johnson effect, might be called the "bigger is better" syndrome. Utilities tend to be conservative organizations that rely on past strategies and practices. Making large investments in relatively few resources had been the rule through the 1980s and into the 1990s. Because of this history, utilities may not naturally support smaller scale resources, distributed resources or programmatic solutions to energy efficiency.[38]

Regulation can compensate for these biases by conducting clear-headed analysis, using processes that bring forth a maximum of relevant information and, very importantly, identifying the risk that these biases might introduce into utility resource acquisition. In the next section, we will take a close look at the many risks facing generation resource investments, which involve some of the most important and complex decisions that regulators and utilities make.

38 To be fair, smaller scale resources can add transaction and labor expenses for which the utility would not earn a return under traditional cost of service regulation, which helps to explain limited utility interest in these options.

3. COSTS AND RISKS

OF NEW GENERATION RESOURCES

THE CAPITAL INVESTED BY U.S. ELECTRIC UTILITIES TO BUILD A SMARTER, CLEANER, MORE RESILIENT ELECTRICITY SYSTEM OVER THE NEXT TWO DECADES WILL GO TOWARDS UTILITIES' GENERATION, TRANSMISSION AND DISTRIBUTION SYSTEMS.

In this section we'll take an in-depth look at costs and risks of new generation resources, for several reasons:

- Generation investment will be the largest share of utility spending in the current build cycle; this is where the largest amount of consumer and investor dollars will be at stake.
- Today's decisions about generation investment can shape tomorrow's decisions about transmission and distribution investment (by reducing or increasing the need for such investment).
- Technology breakthroughs—in energy storage, grid management, solar PV, and elsewhere—could radically transform our need for base load power within the useful lives of power plants being built today.
- Generation resources are among utilities' most visible and controversial investments and can be a lightning rod for protest and media attention, intensifying scrutiny on regulatory and corporate decision-makers.
- The industry's familiarity with traditional generating resources (e.g., large centralized fossil and nuclear plants) and relative lack of familiarity with newer alternatives (e.g., demand-side resources such as energy efficiency and demand response, or smaller, modular generating resources like combined heat and power) could lead regulators and utilities to underestimate risks associated with traditional resources and overestimate risks of newer resources.
- Finally, investment decisions about generation resources (especially nuclear power) during the last major build cycle that was led by vertically-integrated utilities, in the 1970s and 80s, destroyed tens of billions of dollars of consumer and shareholder wealth.

For these and other reasons, a comprehensive look at risks and costs of today's generation resources is in order.

While this discussion is most directly applicable to regulators (and other parties) in vertically-integrated states where electric utilities build and own generation, it also has implications for regulators (and other parties) in restructured states. For example, regulators in some restructured states (e.g., Massachusetts) are beginning to allow transmission and distribution (T&D) utilities to own generation again, specifically small-scale renewable generation to comprise a certain percentage of a larger renewable portfolio standard. Further, enhanced appreciation of the risks embedded in T&D utilities' supply portfolios could induce regulators to require utilities to employ best practices with regard to portfolio management, thereby reducing the risks and costs of providing electricity service.[39] Finally, regulators in all states can direct electric utilities to invest in cost-effective demand-side resources, which, as the following discussion makes clear, are utilities' lowest-cost and lowest-risk resources.

PAST AS PROLOGUE: FINANCIAL DISASTERS FROM THE 1980s

The last time regulated U.S. utilities played a central role in building significant new generating capacity additions as part of a major industry-wide build cycle was during the 1970s and 80s.[40] At the time the industry's overwhelming focus was on nuclear power, with the Nuclear Regulatory Commission (NRC) licensing construction of more than 200 nuclear power plants.

The difficulties the industry experienced were numerous and well-known: more than 100 nuclear plants abandoned in various stages of development;[41] cost overruns so high that the average plant cost three times initial estimates;[42] and total "above-market" costs to society—ratepayers, taxpayers and shareholders—estimated at more than $200 billion.[43]

39 For a discussion of energy portfolio management, see William Steinhurst et al., *Energy Portfolio Management: Tools & Resources for State Public Utility Commissions* (Cambridge, MA: Synapse Energy Economics, 2006), http://www.naruc.org/Grants/Documents/NARUC%20PM%20FULL%20DOC%20FINAL1.pdf.

40 The natural gas build-out of the 1990s and early 2000s was led by independent power producers, not regulated utilities.

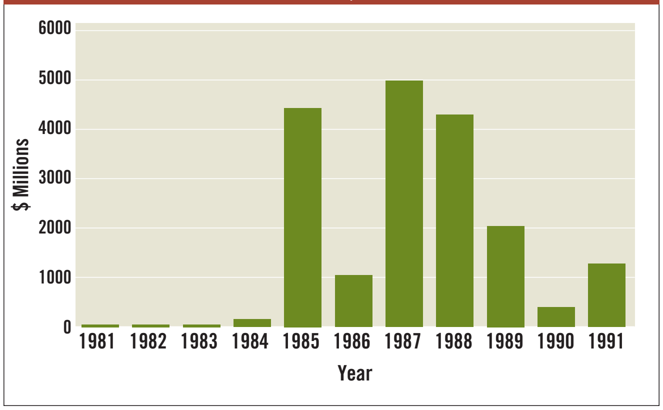
41 Peter Bradford, *Subsidy Without Borders: The Case of Nuclear Power* (Cambridge, MA: Harvard Electricity Policy Group, 2008).

42 U.S. Energy Information Administration, *An Analysis of Nuclear Power Plant Construction Costs* (Washington, DC: U.S. Energy Information Administration, 1986).

43 Huntowski, Fisher and Patterson, *Embrace Electric Competition*, 18. Estimate is expressed in 2007 dollars.

Figure 8

U.S. UTILITY GENERATION INVESTMENT DISALLOWED BY REGULATORS, 1981-1991



While the vast majority of these losses were borne by ratepayers and taxpayers, utility shareholders were not immune. Between 1981 and 1991, U.S. regulators disallowed about $19 billion of investment in power plants by regulated utilities (**Figure 8**).[44] During this time, the industry invested approximately $288 billion, so that the disallowances equated to about 6.6 percent of total investment. The majority of the disallowances were related to nuclear plant construction, and most could be traced to a finding by regulators that utility management was to blame.

To put this in perspective for the current build cycle, consider **Figure 9**. For illustrative purposes, it shows what disallowances of 6.6 percent of IOU investment would look like for shareholders in the current build cycle, using Brattle's investment projections for the 2010-2030 timeframe referenced earlier. The table also shows what shareholder losses would be if regulators were to disallow investment a) at half the rate of disallowances of the 1981-91 period; and b) at twice the rate of that period.[45]

Figure 9

ILLUSTRATIVE PROSPECTIVE SHAREHOLDER LOSSES DUE TO REGULATORY DISALLOWANCES, 2010-2030

Disallowance Ratio	Investment	
	$1.5 T	$2.0 T
3.3%	$34.6 B	$46.2 B
6.6%	$69.3 B	$92.4 B
13.2%	$138.6 B	$184.8 B

Obviously, the *average* disallowance ratio from the 1980s doesn't tell the full story. A few companies bore the brunt of the regulatory action. One of the largest disallowances was for New York's Nine Mile Point 2 nuclear plant, where the $2 billion-plus disallowance was estimated to be 34 percent of the project's original capital cost.[46] When Niagara Mohawk, the lead utility partner in the project, wrote down its investment in the project by $890 million, Standard & Poor's lowered the company's credit rating by two notches, from A- to BBB. Thus the risk inherent in building the Nine Mile Point 2 plant was visited on investors, who experienced a loss of value of at least $890 million, and consumers, who faced potentially higher interest rates going forward. A major theme of this paper is how consumer and investor interests are intertwined, and how both are served by strategies that limit risk.

Another large disallowance was levied on Pacific Gas and Electric for the Diablo Canyon nuclear station in California. The disallowance took the form of a "performance plan" that set consumers' price for power at a level that was independent of the plant's actual cost. In its 1988 decision, the California Public Utilities Commission approved a settlement whereby PG&E would collect $2 billion less, calculated on a net present value basis, than it had spent to build the plant. The CPUC's decision to approve the disallowance was controversial, and some felt it didn't go far enough. The California Division of Ratepayer Advocate (DRA) calculated PG&E's actual "imprudence" to be $4.4 billion (about 75 percent of the plant's final cost), and concluded that customers ultimately paid $2.4 billion more than was prudent for the plant—even after the $2 billion disallowance.[47]

A major theme of this paper is how consumer and investor interests are intertwined, and how both are served by strategies that limit risk.

These two large disallowances could be joined by many other examples where unrecognized risk "came home to roost." Consider the destruction of shareholder equity that occurred when Public Service of New Hampshire (PSNH) declared bankruptcy in 1988 because of the burden of its investment in the Seabrook Nuclear Unit, or the enormous debt burden placed on ratepayers by the failure of New York's largest utility, Long Island Lighting Company (LILCO), or the 1983 multi-billion dollar municipal bond default by the Washington Public Power Supply System (WPPSS) when it abandoned attempts to construct five nuclear units in southeast Washington.

44 Lyon and Mayo, *Regulatory opportunism*, 632.
45 Assumes 70 percent of investment is by regulated entities. Illustrative estimates do not include potential losses for utility customers or taxpayers.
46 Fred I. Denny and David E. Dismukes, *Power System Operations and Electricity Markets* (Boca Raton, FL: CRC Press, 2002), 17.
47 The California Public Utilities Commission Decision is available on the Lexis database at: 1988 Cal. PUC LEXIS 886; 30 CPUC2d 189; 99 P.U.R.4th 141, December 19, 1988; As Amended June 16, 1989.

All of these financial disasters share four important traits:

- a weak planning process;
- the attempted development of large, capital-intensive central generation resources;
- utility management's rigid commitment to a preferred investment course; and
- regulators' unwillingness to burden consumers with costs judged retrospectively to be imprudent.

We do not propose to assess blame twenty-five years later, but we do question whether the regulatory process correctly interpreted the risk involved in the construction of these plants—whether, with all risks accounted for, these plants should actually have been part of a "least cost" portfolio for these utilities. The lesson is clear: both investors and customers would have been much better served if the regulators had practiced "risk-aware" regulation.

Finally, while the financial calamities mentioned here rank among the industry's worst, the potential for negative consequences is probably higher today. Since the 1980s, electric demand has grown significantly while the environmental risks associated with utility operations, the costs of developing new generation resources, and the pace of technology development have all increased substantially. And, as noted earlier, electric utilities have entered the current build cycle with lower financial ratings than they had in the 1980s.

CHARACTERISTICS OF GENERATION RESOURCES

A utility's generation portfolio typically consists of a variety of resources that vary in their costs and operating characteristics. Some plants have high capital costs but lower fuel costs (e.g., coal and nuclear) or no fuel costs (e.g., hydro, wind, solar PV). Other plants have lower capital costs but relatively high fuel and operating costs (e.g., natural gas combined cycle). Some plants are designed to operate continuously in "base load" mode, while others are designed to run relatively few hours each year, ramping up and down quickly.

Some resources (including demand response) offer firm capacity in the sense that they are able to be called upon, or "dispatchable," in real time, while other resources are not dispatchable or under the control of the utility or system operator (e.g., some hydro, wind, solar PV).

Generation resources also vary widely in their design lives and exposure to climate regulations, among other differences.

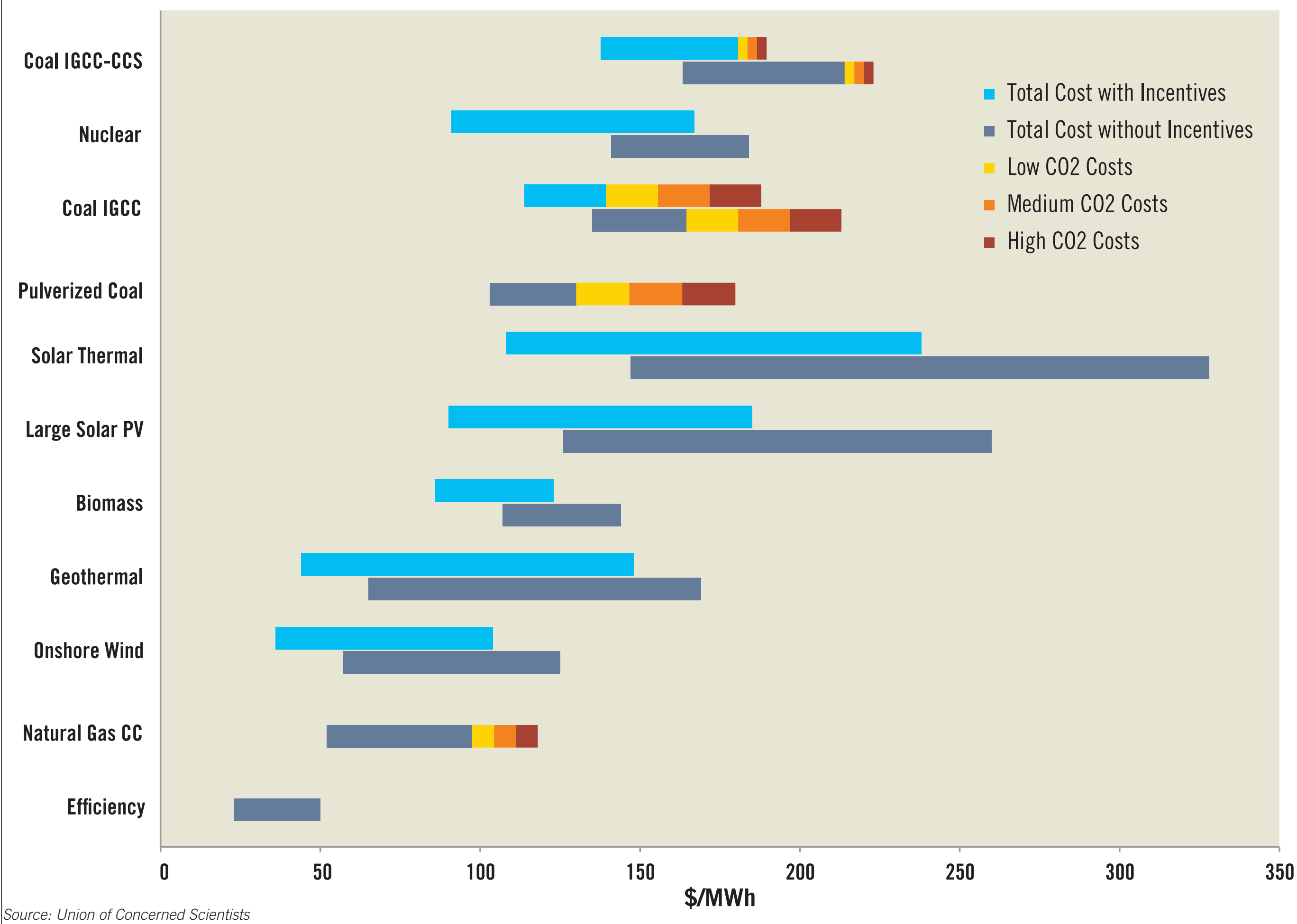
None of these characteristics *per se* makes a resource more or less useful in a utility's resource "stack." Some utility systems operate with a large percentage of generation provided by base load plants. Other systems employ a large amount of non-dispatchable generation like wind energy, combined with flexible gas or hydro generation to supply capacity. What's important is how the resources combine in a portfolio.

For example, in 2008 the Colorado Public Utilities Commission determined that an optimum portfolio for Xcel Energy would include a large amount of wind production, mixed in with natural gas generation and older base load coal plants. Xcel has learned how to manage its system to accommodate large amounts of wind production even though wind is not a "firm" resource. In October 2011, Xcel Energy set a world record for wind energy deployment by an integrated utility: in a one-hour period, wind power provided 55.6 percent of the energy delivered on the Xcel Colorado system.[48]

48 Mark Jaffe, "Xcel Sets World Record for Wind Power Generation," *The Denver Post*, November 15, 2011, http://www.denverpost.com/breakingnews/ci_19342896.

Figure 10

LEVELIZED COST OF ELECTRICITY FOR VARIOUS GENERATION TECHNOLOGIES IN 2015 (2010$)



Source: Union of Concerned Scientists

DECIPHERING THE LEVELIZED COST OF ELECTRICITY

Despite the differences between generation resources, it's possible to summarize and compare their respective costs in a single numerical measure. This quantity, called the "levelized cost of electricity," or "LCOE," indicates the cost per megawatt-hour for electricity over the life of the plant. LCOE encompasses all expected costs over the life of the plant, including costs for capital, operations and maintenance (O&M) and fuel.

Three of the most commonly cited sources of LCOE data for new U.S. generation resources are the Energy Information Administration (EIA); the California Energy Commission (CEC); and the international advisory and asset management firm Lazard. In a recent publication, the Union of Concerned Scientists (UCS) combined the largely consensus LCOE estimates from these three sources to produce a graphic illustrating LCOE for a range of resources (**Figure 10**).[49] The data is expressed in dollars per megawatt-hour, in 2010 dollars, for resources assumed to be online in 2015.

The UCS chart allows a visual comparison of the relative LCOEs among the selected group of resources. The width of the bars in the chart reflects the uncertainty in the cost of each resource, including the variation in LCOE that can result in different regions of the U.S. The UCS report also shows the resources' relative exposure to future carbon costs—not surprisingly, coal-based generation would be most heavily affected—as well as their dependence on federal investment incentives.[50]

49 Freese et al., *A Risky Proposition*, 41.

50 The UCS report estimated incentives by including tax credits for a wide range of technologies and both tax credits and loan guarantees for new nuclear plants. Tax credits currently available for wind and biomass were assumed to be extended to 2015 for illustrative purposes.

We'll use these LCOE estimates to illustrate the combined attributes of cost and risk for new generation resources. To do this, we'll take the midpoint of the cost ranges (including a medium estimate for costs associated with carbon controls) for each technology and create an indicative ranking of these resources by highest to lowest LCOE (**Figure 11**).

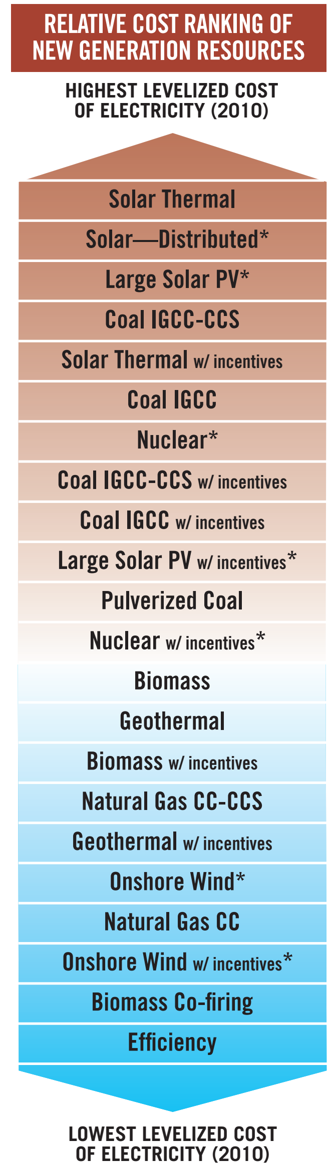
For consistency, we use UCS's data compilation, which is based on 2010 cost estimates, without modification. But the actual cost of nuclear power in 2015 is likely to be sharply higher than this estimate following the Fukushima nuclear accident and recent experience with new nuclear projects. For wind and photovoltaic power, the actual costs in 2015 are likely to be lower than the estimate due to recent sharp cost declines and the 2011 market prices for these resources.[51]

Several observations are in order about this ranking. First, some of the technologies show a very wide range of costs, notably geothermal, large solar PV and solar thermal. The breadth of the range represents, in part, the variation in performance of the technology in various regions of the country. In other words, the underlying cost estimates incorporate geographically varying geothermal and solar energy levels.

Second, the estimates used in this ranking are sensitive to many assumptions; the use of the midpoint to represent a technology in this ranking may suggest greater precision than is warranted. For this reason, the ranking shown in Figure 11 should be considered an indicative ranking. Two resources that are adjacent in the ranking might switch places under modest changes in the assumptions. That said, the ranking is useful for visualizing the relative magnitude of costs associated with various technologies and how those are projected to compare in the next few years.

Finally, the LCOE ranking tells only part of the story. The main point of this paper is that the *price* for any resource does not take into account the relative *risk* of acquiring it. In the next section we will examine these same technologies and estimate the composite risk to consumers, the utility and its investors for each technology.

Figure 11



** Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

The main point of this paper is that the *price* for any resource does not take into account the relative *risk* of acquiring it.

51 For example, in November 2011, the Colorado Public Utilities Commission approved a 25-year power purchase agreement between Xcel Energy and NextEra for wind generation in Colorado. The contract price is $27.50 per MWh in the first year and escalates at 2 percent per year. The levelized cost of the contract over 25 years is $34.75, less than the assumed lowest price for onshore wind with incentives in 2015 in Figure 10. For details, see Colorado PUC Decision No. C11-1291, available at http://www.colorado.gov/dora/cse-google-static/?q=C11-1291&cof=FORIDA10&ie=UTF-8&sa=Search. For more on wind power cost reductions, see Ryan Wiser et al., "Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects" (presentation materials funded by the Wind and Water Power Program of the U.S. Department of Energy, February 2012), http://eetd.lbl.gov/ea/ems/reports/wind-energy-costs-2-2012.pdf. For information on recent PV cost reductions, see Solar Energy Industries Association (SEIA), *U.S. Solar Market Insight Report: 2011 Year in Review: Executive Summary* (Washington, DC: Solar Energy Industries Association, 2012), 10-11, http://www.seia.org/cs/research/solarinsight.

RELATIVE RISK OF NEW GENERATION RESOURCES

In Figure 7 on p. 21, we identified many of the time-related and cost-related risks that attach to a decision to choose a utility resource. We will now examine various generation resource choices in light of these risks, grouping those examples of risk into seven categories:

- **Construction Cost Risk:** includes unplanned cost increases, delays and imprudent utility actions
- **Fuel and Operating Cost Risk:** includes fuel cost and availability, as well as O&M cost risks
- **New Regulation Risk:** includes air and water quality rules, waste disposal, land use, and zoning
- **Carbon Price Risk:** includes state or federal limits on greenhouse gas emissions
- **Water Constraint Risk:** includes the availability and cost of cooling and process water
- **Capital Shock Risk:** includes availability and cost of capital, and risk to firm due to project size
- **Planning Risk:** includes risk of inaccurate load forecasts, competitive pressure

These risks are discussed in detail below.

Intermittency vs. Risk

Certain resources, like wind, solar, and some hydropower facilities, are termed "intermittent" or "variable" resources. This means that while the power produced by them can be well characterized over the long run and successfully predicted in the short run, it cannot be precisely scheduled or dispatched. For that reason, variable resources are assigned a relatively low "capacity value" compared to base load power plants. The operating characteristics of any resource affect how it is integrated into a generation portfolio, and how its output is balanced by other resources.

This characteristic, intermittency, should not be confused with the concept of risk. Recall that risk is the expected value of a loss. In this case, the "loss" would be that the plant does not perform as expected—that it does not fulfill its role in a generation portfolio. For wind or solar resources, intermittency is expected and is accommodated in the portfolio design. Thus, while individual wind towers might be highly intermittent, and a collection of towers in a wind farm less so, a wind farm can also be termed highly reliable and present low risk because it will likely operate as predicted.

CONSTRUCTION COST RISK

Construction cost risk is the risk that the cost to develop, finance and construct a generation resource will exceed initial estimates. This risk depends on several factors, including the size of the project, the complexity of the technology, and the experience with developing and building such projects. The riskiest generation resources in this regard are technologies still in development, such as advanced nuclear and fossil-fired plants with carbon capture and storage. Construction cost risk is especially relevant for nuclear plants due to their very large size and long lead times. (Recall that a large percentage of the disallowed investment during the 1980s was for nuclear plants.) Transmission line projects are also subject to cost overruns, as are other large generation facilities. For example, Duke Energy's Edwardsport coal gasification power plant in Indiana has experienced billion-dollar cost overruns that have raised the installed cost to $5,593 per kilowatt, up from an original estimate of $3,364 per kilowatt.[52]

The lowest construction cost risk attaches to energy efficiency and to renewable technologies with known cost histories. In the middle will be technologies that are variations on known technologies (e.g., biomass) and resources with familiar construction regimes (e.g., gas and coal thermal plants).

FUEL AND OPERATING COST RISK

Fossil-fueled and nuclear generation is assigned "medium risk" for the potential upward trend of costs and the volatility familiar to natural gas supply.[53] Efficiency and renewable generation have no "fuel" risk. Biomass is assigned "medium" in this risk category because of a degree of uncertainty about the cost and environmental assessment of that fuel. Plants with higher labor components (e.g., nuclear, coal) have higher exposure to inflationary impacts on labor costs.

Analysts are split on the question of the future price of natural gas. The large reserves in shale formations and the ability to tap those resources economically through new applications of technology suggest that the price of natural gas may remain relatively low for the future and that the traditional volatility of natural gas prices will dampen. On the other hand, there remains substantial uncertainty about the quantity of economically recoverable shale gas reserves and controversy about the industrial processes used to develop these unconventional resources.

52 John Russell, "Duke CEO about plant: 'Yes, it's expensive,'" *The Indianapolis Star,* October 27, 2011, http://www.indystar.com/article/20111027/NEWS14/110270360/star-watch-duke-energy-Edwardsport-iurc.

53 Research conducted by the late economist Shimon Awerbuch demonstrated that adding renewable resources to traditional fossil portfolios lowers portfolio risk by hedging fuel cost variability; see Awerbuch, "How Wind and Other Renewables Really Affect Generating Costs: A Portfolio Risk Approach" (presentation at the European Forum for Renewable Energy Resources, Edinburgh, UK, October 7, 2005), http://www.eufores.org/uploads/media/Awerbuch-edinburgh_risk-portoflios-security-distver-Oct-20051.pdf. For a discussion of using renewable energy to reduce fuel price risk and environmental compliance in utility portfolios, see Mark Bolinger and Ryan Wiser, *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans* (Berkeley, CA: Lawrence Berkeley National Laboratory, 2005), http://eetd.lbl.gov/ea/ems/reports/58450.pdf.

There is also significant debate at the moment about the future price of coal. Some sources of low-sulfur coal are being depleted, raising the specter of higher production costs. Further, U.S. exports to China and other countries suggest upward pressure on this traditionally stable-priced fuel.

In this report we have steered a middle course on natural gas and coal prices, assuming that the risk of future surprises in natural gas and coal availability and price to be "medium." This is consistent with the price projection for these two generation fuels used by the Energy Information Administration in its current long-term energy forecast. In its most recent estimate, EIA assumes a real annual price escalation between 2010 and 2035 of about 1.3 percent for coal at the mine mouth and 1.8 percent for natural gas at the wellhead.[54]

Finally, operating cost risk includes the potential for catastrophic failure of a resource. This is especially significant for systems that could be taken down by a single point of failure. Contrast the impact of the failure of a turbine at a large steam plant as compared to the failure of a single turbine at a 100-turbine wind farm. The first failure causes the unavailability of 100 percent of capacity; the second failure causes a 1 percent reduction in capacity availability. Even if the probabilities of the failures are widely different, the size of the loss (risk) has cost implications for the reserve capacity (insurance) that must be carried on the large plant. Small outages are much easier to accommodate than large ones.[55]

Intermittency should not be confused with the concept of risk… For wind or solar resources, intermittency is expected and is accommodated in the portfolio design.

Modularity and unit size are also relevant to demand-side resources that are, by their nature, diverse. Designing good energy efficiency programs involves scrutinizing individual measures for the potential that they may not deliver the expected level of energy savings over time. This estimate can be factored into expectations for overall program performance so that the resource performs as expected. Since it would be extremely unlikely for individual measure failures to produce a catastrophic loss of the resource, diverse demand-side resources are, on this measure, less risky than large generation-side resources.

NEW REGULATION RISK

Nuclear generation is famously affected by accidents and the resulting changes in regulations. The recent accident at Fukushima in Japan illustrates how even a seemingly settled technology—in this case, GE boiling water reactors—can receive increased regulatory scrutiny. Further, the future of nuclear waste disposal remains unclear, even though the current fleet of reactors is buffered by reserves that are designed to cover this contingency. For these reasons, we consider nuclear power to face a high risk of future regulations.

Carbon sequestration and storage (CCS) appears to be subject to similar elevated risks regarding liability. The ownership and responsibility for long-term maintenance and monitoring for carbon storage sites will remain an unknown risk factor in coal and gas generation proposed with CCS.

Other thermal generation (e.g., biomass and geothermal) are also given a "medium" probability due to potential air regulations and land use regulations. Finally, as noted above, the price of natural gas, especially shale gas produced using "fracking" techniques, is at risk of future environmental regulation.

CARBON PRICE RISK

Fossil generation without CCS has a high risk of being affected by future carbon emission limits. Although there is no political agreement on the policy mechanism to place a cost on carbon (i.e., tax or cap), the authors expect that the scientific evidence of climate change will eventually compel concerted federal action and that greenhouse gas emissions will be costly for fossil-fueled generation. Energy efficiency, renewable and nuclear resources have no exposure to carbon risk, at least with respect to emissions at the plant.[56]

A more complex story appears when we consider the emissions related to the full life-cycle of generation technologies and their fuel cycles. For example, nuclear fuel production is an energy-intensive and carbon-intensive process on its own. As the cost of emitting carbon rises, we should expect the cost of nuclear fuel to rise.

Similar comments could apply to renewable facilities that require raw materials and fabrication that will, at least in the near-term, involve carbon-emitting production processes. However, these effects are second-order and much smaller than the carbon impact of primary generation fuels or motive power (e.g., coal, gas, wind, sun, nuclear reactions). The exposure of biomass to carbon constraints will depend on the eventual interpretation of carbon offsets and life-cycle analyses. For that reason, biomass and co-firing with biomass is assigned a non-zero risk of "low."

54 U.S. Energy Information Administration, *AEO2012 Early Release Overview*, 12-13.

55 This discussion refers to the *availability factor* of a resource; the *capacity factor* of a resource is a different issue, with implications for generation system design and operation.

56 For a discussion of how larger amounts of energy efficiency in a utility portfolio can reduce risk associated with carbon regulation, see Ryan Wiser, Amol Phadke and Charles Goldman, *Pursuing Energy Efficiency as a Hedge against Carbon Regulatory Risks: Current Resource Planning Practices in the West*, Paper 20 (Washington DC: U.S. Department of Energy Publications, 2008), http://digitalcommons.unl.edu/usdoepub/20.

"Retire or Retrofit" Decisions for Coal-Fired Plants

In this report, we've stressed how risk-aware regulation can improve the outcomes of utility selection of new resources. But many regulators will be focusing on existing power plants during the next few years. A key question facing the industry is whether to close coal plants in the face of new and future EPA regulations, or spend money on control systems to clean up some of the plant emissions and keep them running.

States and utilities are just coming to grips with these sorts of decisions. In 2010, Colorado implemented the new Clean Air Clean Jobs Act, under which the Colorado PUC examined Xcel Energy's entire coal fleet. The Colorado Commission entered a single decision addressing the fate of ten coal units. Some were closed, some were retrofitted with pollution controls, and others were converted to burn natural gas. Elsewhere, Progress Energy Carolinas moved decisively to address the same issue with eleven coal units in North Carolina.

We expect that three types of coal plants will emerge in these analyses: plants that should obviously be closed; newer coal plants that should be retrofitted and continue to run; and "plants in the middle." Decisions about these plants in the middle will require regulators to assess the risk of future fuel prices, customer growth, environmental regulations, capital and variable costs for replacement capacity, etc. In short, state commissions will be asked to assess the risks of various paths forward for the plants for which the economics are subject to debate.

The tools we describe in this report for new resources apply equally well to these situations. Regulators should treat this much like an IRP proceeding (see "Utilizing Robust Planning Processes" on p. 40). Utilities should be required to present multiple different scenarios for their disposition of coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. At the end, regulators should enter a decision that addresses all of the relevant risks.

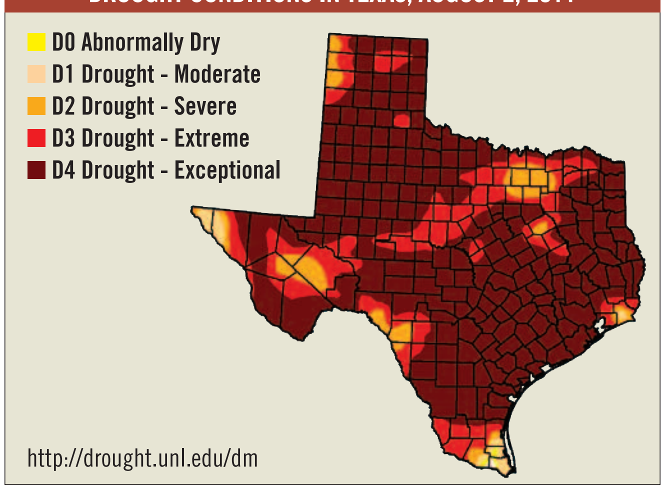
WATER CONSTRAINT RISK

Electric power generation—specifically the cooling of power plants—consumes about 40 percent of all U.S. freshwater withdrawals.[57] The availability and cost of water required for electricity generation will vary with geography but attaches to all of the thermal resources.[58] The recent promulgation by the EPA of the "once-through" cooling rule illustrates the impact that federal regulation can have on thermal facilities; one estimate predicts that more than 400 generating plants providing 27 percent of the nation's generating capacity may need to install costly cooling towers to minimize impacts on water resources.[59] One potential approach, especially for solar thermal, is the use of air-cooling, which significantly lowers water use at a moderate cost to efficiency. Non-thermal generation and energy efficiency have no exposure to this category of risk.

Water emerged as a significant issue for the U.S. electric power sector in 2011. A survey of more than 700 U.S. utility leaders by Black & Veatch indicated "water management was rated as the business issue that could have the greatest impact on the utility industry."[60] Texas suffered from record drought in 2011 at the same time that it experienced all-time highs in electricity demand. **Figure 12** depicts widespread "exceptional drought" conditions in Texas on August 2, 2011,[61] the day before the Electric Reliability Council of Texas (ERCOT) experienced record-breaking peak demand. ERCOT managed to avoid rolling blackouts but warned that continued drought and lack of sufficient cooling water could lead to generation outages totaling "several thousand megawatts."[62]

Figure 12

DROUGHT CONDITIONS IN TEXAS, AUGUST 2, 2011



57 J.F. Kenny et al., "Estimated use of water in the United States in 2005," *U.S. Geological Survey Circular 1344* (Reston, VA: U.S. Geological Survey, 2009), http://pubs.usgs.gov/circ/1344/pdf/c1344.pdf.

58 For a discussion of freshwater use by U.S. power plants, see Kristen Averyt et al., *Freshwater Use by U.S. Power Plants* (Cambridge, MA: Union of Concerned Scientists, 2011), http://www.ucsusa.org/assets/documents/clean_energy/ew3/ew3-freshwater-use-by-us-power-plants.pdf.

59 Bernstein Research, *U.S. Utilities: Coal-Fired Generation is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* (New York: Bernstein Research, 2010), 69.

60 "U.S. Utility Survey Respondents Believe Energy Prices Will Rise Significantly, Place Emphasis on Growing Nexus of Water and Energy Challenge," Black & Veatch press release, June 13, 2011, http://www.bv.com/wcm/press_release/06132011_9417.aspx.

61 National Drought Mitigation Center, "U.S. Drought Monitor: Texas," August 2, 2011, http://droughtmonitor.unl.edu/archive/20110802/pdfs/TX_dm_110802.pdf.

62 Samantha Bryant, "ERCOT examines grid management during high heat, drought conditions," *Community Impact Newspaper*, October 14, 2011, http://impactnews.com/articles/ercot-examines-grid-management-during-high-heat,-drought-conditions.

In addition to drought, water rights could be an issue for electricity generators in Texas (and elsewhere).[63] The North American Electric Reliability Corporation (NERC) points out that in an extreme scenario, up to 9,000 MW of Texas' generation capacity—over 10 percent of ERCOT's total installed capacity—could be at risk of curtailment if generators' water rights were recalled.[64]

CAPITAL SHOCK RISK

This risk is generally proportional to the size of the capital outlay and the time required for construction of a generating unit. Simply put, the larger the capital outlay and the longer that cost recovery is uncertain, the higher the risk to investors. In this regard, nuclear installations and large new coal facilities with CCS face the highest risk. Smaller, more modular additions to capacity and especially resources that are typically acquired through purchase power agreements record less risk. Finally, distributed solar generation, modifications to enable biomass co-firing and efficiency are accorded low exposure to the risk of capital shock.

PLANNING RISK

This risk relates to the possibility that the underlying assumptions justifying the choice of a resource may change, sometimes even before the resource is deployed. This can occur, for example, when electric demand growth is weaker than forecast, which can result in a portion of the capacity of the new resource being excess. In January 2012, lower-than-anticipated electricity demand, combined with unexpectedly low natural gas prices, led Minnesota-based wholesale cooperative Great River Energy to mothball its brand-new, $437 million Spiritwood coal-fired power plant immediately upon the plant's completion. The utility will pay an estimated $30 million next year in maintenance and debt service for the idled plant.[65]

Generation projects with a high ratio of fixed costs and long construction lead times are most susceptible to planning risk. This means that the exposure of base load plants is higher than peaking units, and larger capacity units have more exposure than smaller plants.

In addition to macroeconomic factors like recessions, the electric industry of the early 21st century poses four important unknown factors affecting energy planning. These are 1) the rate of adoption of electric vehicles; 2) the pace of energy efficiency and demand response deployment; 3) the rate of growth of customer-owned distributed generation; and 4) progress toward energy storage. These four unknowns affect various resources in different ways.

Electric vehicles could increase peak demand if customers routinely charge their cars after work, during the remaining hours of the afternoon electrical peak. On the other hand, if electric vehicle use is coupled with time-of-use pricing, this new load has the opportunity to provide relatively desirable nighttime energy loads, making wind generation and nuclear generation and underutilized fossil generation more valuable in many parts of the country.

Energy efficiency (EE) and demand response (DR) affect both electricity (kilowatt-hours) and demand (kilowatts). EE and DR programs differ in relatively how much electricity or demand they conserve. Depending on portfolio design, EE and DR may improve or worsen utility load factors, shifting toward more peaking resources and away from base load plants. Changing customer habits and new "behavioral" EE efforts add to the difficulty in forecasting demand over time.

Distributed generation, especially small solar installation, is expanding rapidly, spurred by new financing models that have lowered the capital outlay from consumers. In addition, we may expect commercial and industrial customers to continue to pursue combined heat and power applications, especially if retail electricity rates continue to rise. Both of these trends will have hard-to-predict impacts on aggregate utility demand and the relative value of different generation resources, but also impacts on primary and secondary distribution investment.

Finally, electric storage at reasonable prices would be a proverbial game-changer, increasing the relative value of intermittent resources such as wind and solar. Microgrids with local generation would also be boosted by low-cost battery storage.

63 For a discussion of how water scarcity could impact municipal water and electric utilities and their bondholders, see Sharlene Leurig, *The Ripple Effect: Water Risk in the Municipal Bond Market* (Boston, MA: Ceres, 2010), http://www.ceres.org/resources/reports/water-bonds/at_download/file. For a framework for managing corporate water risk, see Brooke Barton et al., *The Ceres Aqua Gauge: A Framework for 21st Century Water Risk Management* (Boston, MA: Ceres, 2011), http://www.ceres.org/resources/reports/aqua-gauge/at_download/file.

64 North American Electric Reliability Corporation, *Winter Reliability Assessment 2011/2012* (Atlanta, GA: North American Electric Reliability Corporation, 2011), 29, http://www.nerc.com/files/2011WA_Report_FINAL.pdf.

65 David Shaffer, "Brand new power plant is idled by economy," *Minneapolis StarTribune*, January 9, 2012, http://www.startribune.com/business/134647533.html.

Figure 13

RELATIVE RISK EXPOSURE OF NEW GENERATION RESOURCES							
Resource	Initial Cost Risk	Fuel, O&M Cost Risk	New Regulation Risk	Carbon Price Risk	Water Constraint Risk	Capital Shock Risk	Planning Risk
Biomass	Medium	Medium	Medium	Medium	High	Medium	Medium
Biomass w/ incentives	Medium	Medium	Medium	Medium	High	Low	Medium
Biomass Co-firing	Low	Low	Medium	Low	High	Low	Low
Coal IGCC	High	Medium	Medium	Medium	High	Medium	Medium
Coal IGCC w/ incentives	High	Medium	Medium	Medium	High	Low	Medium
Coal IGCC-CCS	High	Medium	Medium	Low	High	High	High
Coal IGCC-CCS w/ incentives	High	Medium	Medium	Low	High	Medium	High
Efficiency	Low	None	Low	None	None	Low	None
Geothermal	Medium	None	Medium	None	High	Medium	Medium
Geothermal w/ incentives	Medium	None	Medium	None	High	Low	Medium
Large Solar PV	Low	None	Low	None	None	Medium	Low
Large Solar PV w/ incentives	Low	None	Low	None	None	Low	Low
Natural Gas CC	Medium	High	Medium	Medium	Medium	Medium	Medium
Natural Gas CC-CCS	High	Medium	Medium	Low	High	High	Medium
Nuclear	Very High	Medium	High	None	High	Very High	High
Nuclear w/ incentives	Very High	Medium	High	None	High	High	Medium
Onshore Wind	Low	None	Low	None	None	Low	Low
Onshore Wind w/ incentives	Low	None	Low	None	None	None	Low
Pulverized Coal	Medium	Medium	High	Very High	High	Medium	Medium
Solar - Distributed	Low	None	Low	None	None	Low	Low
Solar Thermal	Medium	None	Low	None	High	Medium	Medium
Solar Thermal w/ incentives	Medium	None	Low	None	High	Low	Medium

ESTABLISHING COMPOSITE RISK

In line with the foregoing discussion, the table in **Figure 13** summarizes the degree of exposure of various generation technologies to these seven categories of risk. The technologies listed are taken from UCS's LCOE ranking in Figure 10 on p. 28, plus three more: natural gas combined cycle with CCS, biomass co-firing and distributed solar PV generation. The chart estimates the degree of risk for each resource across seven major categories of risk, with estimates ranging from "None" to "Very High."

Three comments are in order. First, these assignments of relative risk were made by the authors, and while they are informed they are also subjective. As we discuss later, regulators should conduct their own robust examination of the relative costs and risks including those that are unique to their jurisdiction. Second, the assessment of risk for each resource is intended to be relative to each other, and not absolute in a quantitative sense. Third, while there are likely some correlations between these risk categories—resources with low fuel risk will have low carbon price exposure, for example—other variables exhibit substantial independence.

Figure 14

RELATIVE COST RANKING AND RELATIVE RISK RANKING OF NEW GENERATION RESOURCES

HIGHEST LEVELIZED COST OF ELECTRICITY (2010)	HIGHEST COMPOSITE RISK
Solar Thermal	Nuclear
Solar—Distributed*	Pulverized Coal
Large Solar PV*	Coal IGCC-CCS
Coal IGCC-CCS	Nuclear w/ incentives
Solar Thermal w/ incentives	Coal IGCC
Coal IGCC	Coal IGCC-CCS w/ incentives
Nuclear*	Natural Gas CC-CCS
Coal IGCC-CCS w/ incentives	Biomass
Coal IGCC w/ incentives	Coal IGCC w/ incentives
Large Solar PV w/ incentives*	Natural Gas CC
Pulverized Coal	Biomass w/ incentives
Nuclear w/ incentives*	Geothermal
Biomass	Biomass Co-firing
Geothermal	Geothermal w/ incentives
Biomass w/ incentives	Solar Thermal
Natural Gas CC-CCS	Solar Thermal w/ incentives
Geothermal w/ incentives	Large Solar PV
Onshore Wind*	Large Solar PV w/ incentives
Natural Gas CC	Onshore Wind
Onshore Wind w/ incentives*	Solar—Distributed
Biomass Co-firing	Onshore Wind w/ incentives
Efficiency	Efficiency
LOWEST LEVELIZED COST OF ELECTRICITY (2010)	LOWEST COMPOSITE RISK

* *Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

The risk ranking shows a clear difference between renewable resources and non-renewable resources. Nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

Figure 15

RELATIVE COST AND RISK RANKINGS OF NEW GENERATION RESOURCES WITHOUT INCENTIVES

HIGHEST LEVELIZED COST OF ELECTRICITY (2010)	HIGHEST COMPOSITE RISK
Solar Thermal	Nuclear
Solar–Distributed*	Pulverized Coal
Large Solar PV*	Coal IGCC-CCS
Coal IGCC-CCS	Coal IGCC
Coal IGCC	Natural Gas CC-CCS
Nuclear*	Biomass
Pulverized Coal	Natural Gas CC
Biomass	Geothermal
Geothermal	Biomass Co-firing
Natural Gas CC-CCS	Solar Thermal
Onshore Wind*	Large Solar PV
Natural Gas CC	Onshore Wind
Biomass Co-firing	Solar–Distributed
Efficiency	Efficiency
LOWEST LEVELIZED COST OF ELECTRICITY (2010)	LOWEST COMPOSITE RISK

* *Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

To derive a ranking of these resources with respect to risk, we assigned numeric values to the estimated degrees of risk (None=0, Very High=4) and totaled the rating for each resource. The scores were then renormalized so that the score of the highest-risk resource is 100 and the others are adjusted accordingly. The composite relative risk ranking that emerges is shown in **Figure 14**, which, for ease of comparison, we present alongside the relative cost ranking from Figure 11.

The risk ranking differs from the cost ranking in several important ways. First, the risk ranking shows a clear difference between renewable resources and non-renewable resources. Second, nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

To illustrate how resources stack up against each other in more general terms, and for simplicity of viewing, **Figure 15** presents those same rankings without information about incentives.

To test the robustness of the composite risk ranking, we also examined two rankings where the scores were weighted. In one case, the environmental factors were given double weight; in the other, the cost factors were given double weight. As before, the scores were renormalized so that the highest-scoring resource is set to 100. The results of the unweighted ranking, together with the two weighted rankings, are shown in **Figure 16**. By inspection, one can see that the rank order changes very little across the three methods, so that the risk ranking in Figure 14 appears to be relatively robust. Once again, we emphasize that these figures are intended to show the relative risk among the resources, not to be absolute measures of risk.[66]

Figure 16

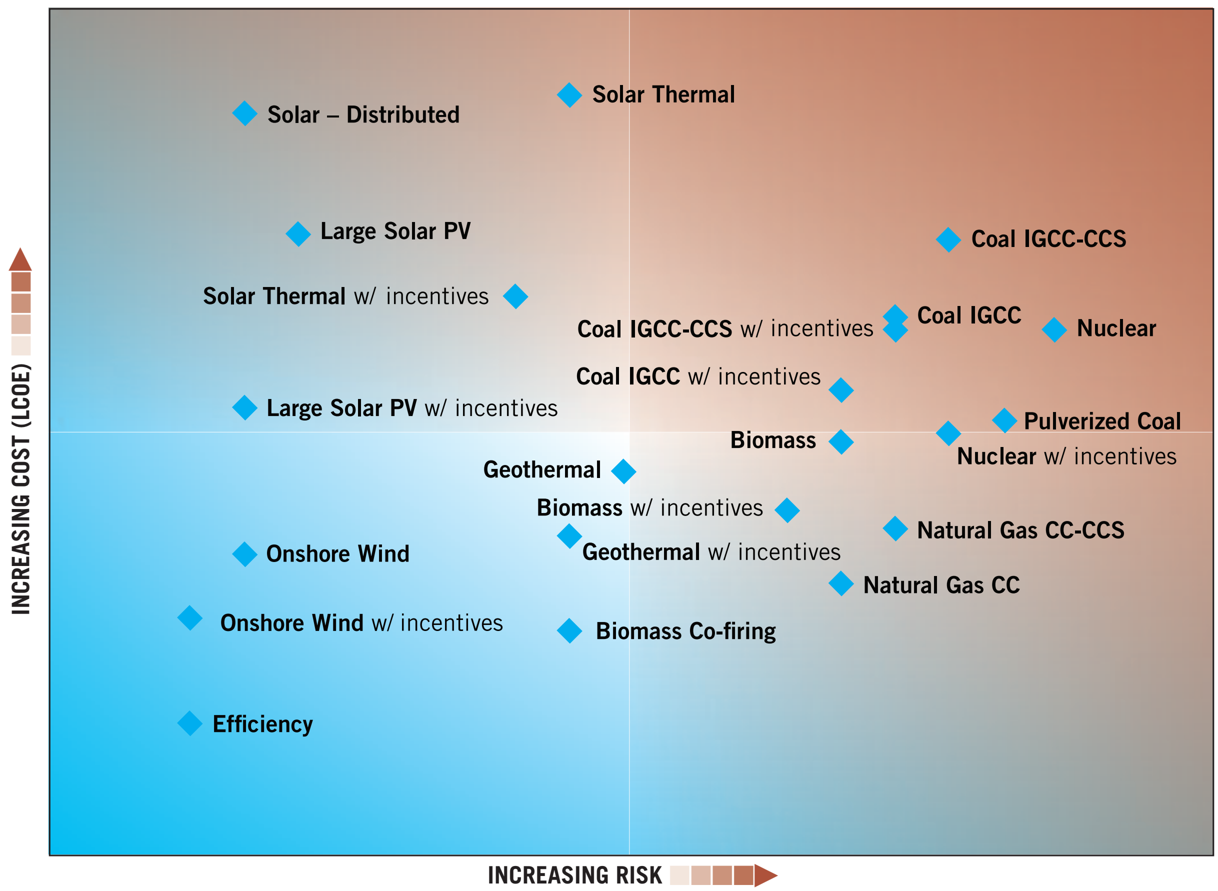
SUMMARY OF RISK SCORES FOR NEW GENERATION RESOURCES

Resource	Composite Score	Environmental Weighted Score	Cost Weighted Score
Biomass	79	79	72
Biomass w/ incentives	74	76	66
Biomass Co-firing	53	57	44
Coal IGCC	84	83	79
Coal IGCC w/ incentives	79	79	72
Coal IGCC-CCS	89	84	87
Coal IGCC-CCS w/ incentives	84	81	80
Efficiency	16	14	16
Geothermal	58	59	52
Geothermal w/ incentives	53	55	46
Large Solar PV	26	22	28
Large Solar PV w/ incentives	21	19	21
Natural Gas CC	79	76	75
Natural Gas CC-CCS	84	79	82
Nuclear	100	91	100
Nuclear w/ incentives	89	83	89
Onshore Wind	21	19	21
Onshore Wind w/ incentives	16	16	15
Pulverized Coal	95	100	82
Solar - Distributed	21	19	21
Solar Thermal	53	52	49
Solar Thermal w/ incentives	47	48	43

66 Dr. Mark Cooper, a longtime utility sector analyst and supporter of consumer interests, recently arrived at similar conclusions about composite risk; see Cooper, *Least-Cost Planning For 21st Century Electricity Supply* (So. Royalton, VT: Vermont Law School, 2011), http://www.vermontlaw.edu/Documents/21st%20Century%20Least%20Cost%20Planning.pdf. Cooper's analysis incorporated not only variations in "risk" and "uncertainty," but also the degrees of "ignorance" and "ambiguity" associated with various resources and the universe of possible future energy scenarios.

Figure 17

PROJECTED UTILITY GENERATION RESOURCES IN 2015
Relative Cost and Relative Risk



Finally, we can combine the information in the cost ranking and the risk ranking into a single chart. **Figure 17** shows how resources compare with each other in the two dimensions of cost and risk. The position of a resource along the horizontal axis denotes the relative risk of each resource, while the position on the vertical axis shows the relative cost of the resource.

4. PRACTICING RISK-AWARE REGULATION:

SEVEN ESSENTIAL STRATEGIES FOR STATE REGULATORS

UTILITY REGULATORS ARE FAMILIAR WITH A SCENE THAT PLAYS OUT IN THE HEARING ROOM: DIFFERENT INTERESTS—UTILITIES, INVESTORS, CUSTOMER GROUPS, ENVIRONMENTAL ADVOCATES AND OTHERS—COMPETE TO REDUCE COST AND RISK FOR THEIR SECTOR AT THE EXPENSE OF THE OTHERS. WHILE THE ADVERSARIAL PROCESS MAY MAKE THIS COMPETITION SEEM INEVITABLE, AN OVERLOOKED STRATEGY (THAT USUALLY LACKS AN ADVOCATE) IS TO REDUCE OVERALL RISK TO EVERYONE. MINIMIZING RISK IN THE WAYS DISCUSSED IN THIS SECTION WILL HELP ENSURE THAT ONLY THE UNAVOIDABLE BATTLES COME BEFORE REGULATORS AND THAT THE PUBLIC INTEREST IS SERVED FIRST.

Managing risk intelligently is arguably the main duty of regulators who oversee utility investment. But minimizing risk isn't simply achieving the least cost today. It is part of a strategy to *minimize overall long term costs*. And, as noted earlier, while minimizing risk is a worthy goal, eliminating risk is not an achievable goal. The regulatory process must provide balance for the interests of utilities, consumers and investors in the presence of risk.

One of the goals of "risk-aware" regulation is avoiding the kind of big, costly mistakes in utility resource acquisition that we've seen in the past. But there is another, more affirmative goal: ensuring that society's limited resources (and consumers' limited dollars) are spent wisely. By routinely examining and addressing risk in every major decision, regulators will produce lower cost outcomes in the long run, serving consumers and the public interest in a very fundamental way.

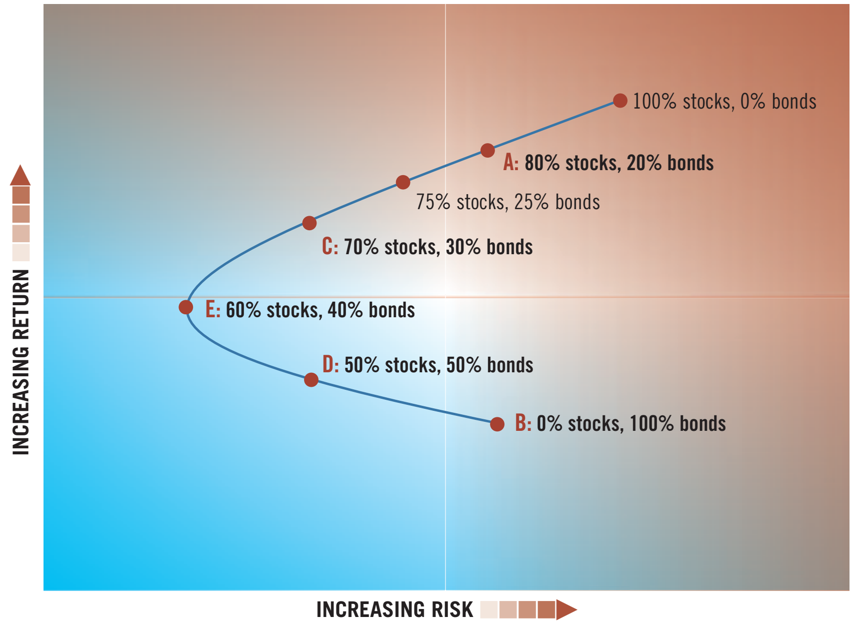
An overlooked strategy (that usually lacks an advocate) is to reduce overall risk to everyone.

WE IDENTIFY SEVEN ESSENTIAL STRATEGIES THAT REGULATORS CAN EMPLOY TO MINIMIZE RISK:

1. **DIVERSIFYING UTILITY SUPPLY PORTFOLIOS** with an emphasis on low-carbon resources;
2. **UTILIZING ROBUST PLANNING PROCESSES** for all utility investment (i.e., generation, transmission, distribution, and demand-side resources like energy efficiency);
3. **EMPLOYING TRANSPARENT RATEMAKING PRACTICES** that reveal risk;
4. **USING FINANCIAL AND PHYSICAL HEDGES**, including long-term contracts;
5. **HOLDING UTILITIES ACCOUNTABLE** for their obligations and commitments;
6. **OPERATING IN ACTIVE, "LEGISLATIVE" MODE**, continually seeking out and addressing risk;
7. **REFORMING AND RE-INVENTING RATEMAKING POLICIES** as appropriate.

Figure 18

RISK/RETURN RELATIONSHIPS AMONG DIFFERENT FINANCIAL PORTFOLIOS
(Illustrative)



We now discuss each of these strategies in more detail.

1. DIVERSIFYING UTILITY SUPPLY PORTFOLIOS

The concept of diversification plays an important role in finance theory. Diversification—investing in different asset classes with different risk profiles—is what allows a pension fund, for example, to reduce portfolio volatility and shield it from outsized swings in value.

Properly chosen elements in a diversified portfolio can increase return for the same level of risk, or, conversely, can reduce risk for a desired level of return. The simple illustration in **Figure 18** allows us to consider the relative risk and return for several portfolios consisting of stocks and bonds. Portfolio A (80% stocks, 20% bonds) provides a higher predicted return than Portfolio B (0% stocks, 100% bonds) even though both portfolios have the same degree of risk. Similarly, Portfolios C and D produce different returns at an identical level of risk that is lower than A and B. Portfolio E (60% stocks, 40% bonds) has the lowest risk, but at the cost of a lower return than Portfolios A and C. The curve in Figure 18 (and the corresponding surface in higher dimensions) is called an *efficient frontier*.

We could complicate the example—by looking at investments in cash, real estate, physical assets, commodities or credit default swaps, say, or by distinguishing between domestic and international stocks, or between bonds of various maturities—but the general lesson would be the same: diversification helps to lower the risk in a portfolio.

Portfolios of utility investments and resource mixes can be analyzed similarly. Instead of return and risk, the analysis would examine cost and risk. And instead of stocks, bonds, real estate and gold, the elements of a utility portfolio are different types of power plants, energy efficiency, purchased power agreements, and distributed generation, among many other potential elements. Each of these elements can be further distinguished by type of fuel, size of plant, length of contract, operating characteristics, degree of utility dispatch control, and so forth. Diversification in a utility portfolio means including various supply and demand-side resources that behave independently from each other in different future scenarios. Later we will consider these attributes in greater detail and discuss what constitutes a diversified utility portfolio.

For a real-world illustration of how diversifying resources lowers cost and risk in utility portfolios, consider the findings of the integrated resource plan recently completed by the Tennessee Valley Authority (TVA).[67] TVA evaluated five resource strategies that were ultimately refined into a single "recommended planning direction" that will guide TVA's resource investments. The resource strategies that TVA considered were:

- **Strategy A:** Limited Change in Current Resource Portfolio[68]
- **Strategy B:** Baseline Plan Resource Portfolio
- **Strategy C:** Diversity Focused Resource Portfolio
- **Strategy D:** Nuclear Focused Resource Portfolio
- **Strategy E:** EEDR (Energy Efficiency/Demand Response) and Renewables Focused Resource Portfolio

67 TVA, a corporation owned by the federal government, provides electricity to nine million people in seven southeastern U.S. states; see http://www.tva.com/abouttva/index.htm.

68 As of spring 2010, TVA's generation mix consisted mainly of coal (40 percent), natural gas (25 percent) and nuclear (18 percent); see TVA, 73.

Figure 19

TVA ANALYSIS OF RESOURCE PLAN COSTS & FINANCIAL RISK

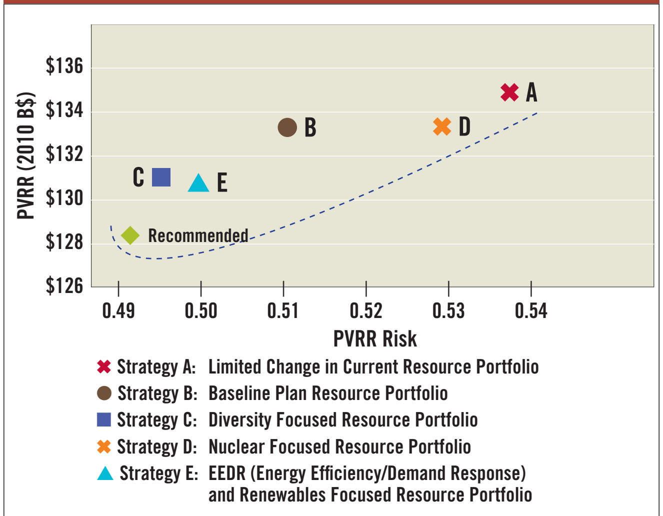


Figure 19 illustrates how these strategies mapped out along an "efficient frontier" according to TVA's analysis of cost and risk.[69] The lowest-cost, lowest-risk strategies were the ones that diversified TVA's resource portfolio by increasing TVA's investment in energy efficiency and renewable energy.[70] The highest-cost, highest-risk strategies were those that maintained TVA's current resource portfolio (mostly coal, natural gas and nuclear) or emphasized new nuclear plant construction.

The TVA analysis is very careful and deliberate. To the extent that other analyses reached conclusions thematically different from TVA's, we would question whether the costs and risks of all resources had been properly evaluated. We would also posit that resource investment strategies that differ directionally from TVA's "recommended planning direction" would likely expose customers (and, to some extent, investors) to undue risk. Finally, given the industry's familiarity with traditional resources—and the possibility that regulators and utilities may therefore underestimate the costs and risks of those resources—the TVA example illustrates how careful planning reveals the costs and risks of maintaining resource portfolios that rely heavily on large base load fossil and nuclear plants.

Robust planning processes like TVA's are therefore essential to making risk-aware resource choices. It is to these planning processes that we now turn.

2. UTILIZING ROBUST PLANNING PROCESSES

In the U.S., there are two basic utility market structures: areas where utilities own or control their own generating resources (the "vertically integrated" model), and areas where competitive processes establish wholesale prices (the "organized market" model).

In many vertically integrated markets and in some organized markets, regulators oversee the capital investments of utilities with a process called "integrated resource planning," or IRP. Begun in the 1980s, integrated resource planning is a tool to ensure that the utilities, regulators and other stakeholders have a common understanding of a full spectrum of possible utility resources; that the options are examined in a structured, disciplined way in administrative proceedings; that demand-side resources get equal consideration alongside supply-side resources; and that the final resource plan is understood (if not necessarily accepted) by all.

Elements of a Robust IRP Process

IRP oversight varies in sophistication, importance and outcomes across the states. Because a robust IRP process is critical to managing risk in a utility, we describe a model IRP process that is designed to produce utility portfolios that are lower risk and lower cost.[71]

These elements characterize a robust IRP process:

- The terms and significance of the IRP approval (including implications for cost recovery) are clearly stated at the outset, often in statute or in a regulatory commission's rules.
- The regulator reviews and approves the modeling inputs used by the utility (e.g., demand and energy forecasts, fuel cost projections, financial assumptions, discount rate, plant costs, fuel costs, energy policy changes, etc.).
- The regulator provides guidance to utility as to the policy goals of the IRP, perhaps shaping the set of portfolios examined.
- Utility analysis produces a set of resource portfolios and analysis of parameters such as future revenue requirement, risk, emissions profile, and sensitivities around input assumptions.
- In a transparent public process, the regulator examines competing portfolios, considering the utility's analysis as well as input from other interested parties.
- Demand resources such as energy efficiency and demand response are accorded equal status with supply resources.
- The regulator approves a plan and the utility is awarded a "presumption of prudence" for actions that are consistent with the approved IRP.
- The utility acquires (i.e., builds or buys) the resources approved in the IRP, possibly through a competitive bidding regime.
- Future challenges to prudence of utility actions are limited to the execution of the IRP, not to the selection of resources approved by the regulator.

69 TVA, 161.

70 In the end, TVA settled on a "recommended planning direction" that calls for demand reductions of 3,600 to 5,100 MW, energy efficiency savings of 11,400 to 14,400 GWh, and renewable generating capacity additions of 1,500 to 2,500 MW by 2020. At the same time, TVA plans to retire 2,400 to 4,700 MW of coal-fired capacity by 2017. See TVA, 156.

71 For an example of an IRP that uses sophisticated risk modeling tools, see PacifiCorp, *2011 Integrated Resource Plan* (Portland, OR: PacifiCorp, 2011), http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP-MainDocFinal_Vol1-FINAL.pdf.

IRP: "Accepted" vs. "Approved" Plans

There are two varieties of IRP plans: "accepted plans" and "approved plans." Accepted plans are those where regulators examine the utility's process for developing its proposed plan. This can be a thorough review in which the Commission solicits the opinion of other parties as to whether the utility undertook a transparent, inclusive, and interactive process. If the regulator is convinced, the regulator "accepts" the utility's plan. This allows the utility to proceed but does not include any presumption about the Commission's future judgment concerning the prudence of actions taken under the plan.

With an "approved plan" the regulator undertakes a thorough review of the utility's preferred plan, possibly along with competing IRP plans submitted by other parties. Typically the scrutiny is more detailed and time-consuming in this version of IRP and the regulatory agency is immersed in the details of competing plans. At the end of the process, the regulator "approves" an IRP plan. This approval typically carries with it a presumption that actions taken by the utility consistent with the plan (including its approved amendments) are prudent. Over time, a Commission that approves an IRP plan will typically also examine proposed changes to the plan necessitated by changing circumstances.

In this report, we will focus on the "approved plan" process, although many of our findings apply equally to regulators that employ the "accepted plan" process.

A few of these elements deserve more elaboration.

Significance. The IRP must be meaningful and enforceable; there must be something valuable at stake for the utility and for other parties. From the regulator's point of view, the resource planning process must review a wide variety of portfolio choices whose robustness is tested and compared under different assumptions about the future. From the utilities' perspective, acceptance or approval of an IRP should convey that regulators support the plan's direction, even though specific elements may evolve as circumstances change. If a utility ignores the approved IRP or takes actions that are inconsistent with an IRP without adequate justification, such actions may receive extra scrutiny at the point where the utility seeks cost recovery.

Multiple scenarios. Many different scenarios will allow a utility to meet its future load obligations to customers. These scenarios will differ in cost, risk, generation characteristics, fuel mix, levels of energy efficiency, types of resources, sensitivity to changes in fuel cost, and so forth. While one scenario might apparently be lowest cost under baseline assumptions, it may not be very resilient under different input assumptions. Further, scenarios will differ in levels of risk and how that risk may be apportioned to different parties (e.g., consumers or shareholders). Regulators, with input from interested parties, should specify the types of scenarios that utilities should model and require utilities to perform sensitivity analyses, manipulating key variables.

Consistent, active regulation. An IRP proceeding can be a large, complex undertaking that occurs every two or three years, or even less frequently. It is critical that regulators become active early in the process and stay active throughout. The regulator's involvement should be consistent, even-handed and focused on the big-ticket items. Of course, details matter, but the process is most valuable when it ensures that the utility is headed in the right direction and that its planning avoids major errors. The regulator should then monitor a utility's performance and the utility should be able to trust the regulator's commitment to the path forward laid out in the IRP.

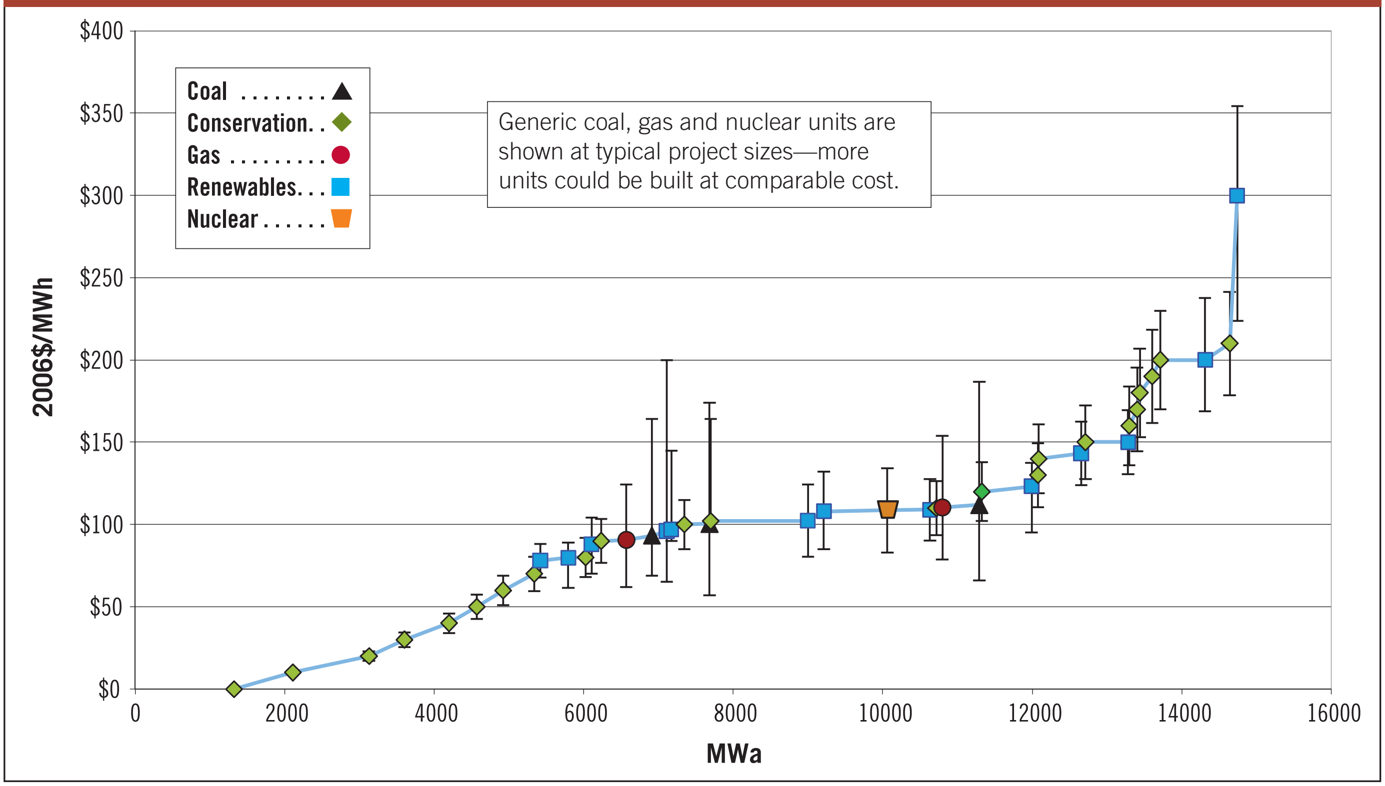
Stakeholder involvement. There are at least two good reasons to encourage broad stakeholder involvement in an IRP process. First, parties besides the utility will bring new ideas, close scrutiny and contrasting analysis to the IRP case, all of which helps the regulator to make an informed, independent decision. Second, effective stakeholder involvement can build support for the IRP that is ultimately approved, heading off collateral attacks and judicial appeals. An approved IRP will affect the fortunes of many and will signal the direction that the regulator wishes the utility to take with its supply-side and demand-side resources. Because an IRP decision is something of a political document in addition to being a working plan, regulators will be well-served to include as broad a group of stakeholders as possible when developing the IRP.

An approved IRP will affect the fortunes of many and will signal the direction that the regulator wishes the utility to take with its supply-side and demand-side resources… [R]egulators will be well-served to include as broad a group of stakeholders as possible when developing the IRP.

Transparency. Regulators must ensure that, to the greatest extent possible, all parties participating in the IRP process have timely access to utility data. Certain data may be competitively sensitive and there is often pressure on the regulator to restrict unduly the access to such data. One possible solution to this challenge is to use an "independent evaluator" who works for the commission, is trusted by all parties and has access to all the data, including proprietary data. The independent evaluator can verify the modeling of the utility and assist the regulator in making an informed decision. The cost of an independent evaluator will be small in comparison to the benefits (or avoided mistakes) that the evaluator will enable. An independent evaluator will also add

Figure 20

PORTFOLIO ANALYSIS ON ONE PAGE
How Energy Efficiency Can Substitute for Generation Resources



credibility to the regulators' decision. In any event, the integrity of the IRP process will depend on regulators' ability to craft processes that are trusted to produce unbiased results.

Competitive bidding. A successful IRP will lower risk in the design of a utility resource portfolio. After the planning process, utilities begin acquiring approved resources. Some states have found it beneficial to require the utility to undertake competitive bidding for all resources acquired by a utility pursuant to an IRP. If the utility will build the resource itself, the regulator may require the utility to join the bidding process or commit to a cap on the construction cost of the asset.[72]

Role of Energy Efficiency. A robust IRP process will fully consider the appropriate levels of energy efficiency, including demand response and load management, that a utility should undertake. Properly viewed and planned for, energy efficiency can be considered as equivalent to a generation resource. Regulators in some states list projected energy efficiency savings on the "loads and resources table" of the utility, adjacent to base load and peaking power plants. In Colorado, energy efficiency is accorded a "reserve margin" in the integrated resource plan, as is done with generation resources.[73]

Since its inception in 1980, the Northwest Power and Conservation Council, which develops and maintains a regional power plan for the Pacific Northwest, has stressed the role of energy efficiency in meeting customers' energy needs. **Figure 20** shows the Council's analysis, demonstrating the elements of a diversified energy portfolio and the role that energy efficiency (or "conservation") can play in substituting for generation resources at various levels of cost.[74]

Appendix 2 contains additional discussion of some of the modeling tools available to regulators.

3. EMPLOYING TRANSPARENT RATEMAKING PRACTICES

Economist Alfred Kahn famously observed that "all regulation is incentive regulation," meaning that any type of economic regulation provides a firm with incentives to make certain choices. Indeed, utility rate regulation's greatest effect may not be its ability to limit prices for consumers in the short run, but rather the incentives it creates for utilities in the longer run.

72 For a discussion of the use of competitive bidding in resource acquisition, see Susan F. Tierney and Todd Schatzki, *Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices* (Boston, MA: Analysis Group, 2008), http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/Competitive_Procurement.pdf.

73 For Xcel Energy in Colorado, energy efficiency is listed on the "loads and resources" table as a resource. As such, it is logical that some fraction of the planned-for load reduction might not materialize. That portion is then assigned the standard resource reserve margin of approximately 15 percent. The planning reserve margin is added to the projected peak load, which must be covered by the combined supply-side and demand-side resources in the table.

74 Tom Eckman, "The 6th Power Plan… and You" (presentation at the Bonneville Power Administration Utility Energy Efficiency Summit, Portland, Ore., March 17, 2010), http://www.bpa.gov/Energy/N/utilities_sharing_ee/Energy_Smart_Awareness/pdf/0A_EESummit_Gen-Session_Public_Power.pdf.

There have been many debates through the years about the incentives that utility cost of service regulation provides. These range from the academic and formal (e.g., the aforementioned Averch-Johnson effect, which says that rate-regulated companies will have an inefficiently high ratio of capital to labor) to the common sense (e.g., price cap regulation can induce companies to reduce quality of service; the throughput incentive discourages electric utilities from pursuing energy efficiency, etc.).

While regulators may want to limit their role to being a substitute for the competition that is missing in certain parts of the electric industry, it is rarely possible to limit regulation's effects that way. The question is usually not how to eliminate stray incentives in decisions, but rather which ones to accept and address.

To contain risk and meet the daunting investment challenges facing the electric industry, regulators should take care to examine exactly what incentives are being conveyed by the details of the regulation they practice. We examine four components of cost of service regulation that affect a utility's perception of risk, and likely affect its preference for different resources.

Current Return on Construction Work in Progress. There is a long-standing debate about whether a utility commission should allow a utility to include in its rates investment in a plant during the years of its construction. Construction Work in Progress, or "CWIP," is universally favored by utility companies and by some regulators, but almost universally opposed by advocates for small and large consumers and by other regulators. CWIP is against the law in some states, mandated by law in others.

The main argument against CWIP is that it requires consumers to pay for a plant often years before it is "used and useful," so that there isn't a careful match between the customers who pay for a plant and those who benefit from it. Proponents of CWIP point out that permitting a current return on CWIP lessens the need for the utility to issue debt and equity, arguably saving customers money, and that CWIP eases in the rate increase, compared to the case where customers feel the full costs of an expensive plant when the plant enters service. Opponents counter by noting that customers typically have a higher discount rate than the utilities' return on rate base, so that delaying a rate hike is preferred by consumers, even if the utility borrows more money to finance the plant until it enters service.

Setting aside the near-religious debate about the equity of permitting CWIP in rate base, there is another relevant consideration. Because CWIP can help utilities secure financing and phase in rate increases, CWIP is often misunderstood as a tool for reducing risk. This is not true.

CWIP, Risk Shifting and Progress Energy's Levy Nuclear Plant

In late 2006, Progress Energy announced plans to build a new nuclear facility in Levy County, Florida, a few months after the state legislature approved construction work in progress (CWIP) customer financing. The site is about 90 miles north of Tampa, near the Gulf of Mexico. In 2009, Progress customers began paying for the Levy plant, which was expected to begin service in 2016 and be built at a cost of $4-6 billion. By the end of 2011, Progress customers had paid $545 million toward Levy's construction expenses.

The Levy plant is now projected to cost up to $22 billion, roughly four times initial estimates, and that number could keep climbing. (In March 2012, Progress Energy's market value as a company was almost $16 billion; the combined market value of Duke Energy and Progress Energy, which are seeking to merge and are pursuing construction of five nuclear facilities between them, is about $44 billion.) Levy's expected in-service date has pushed beyond 2021 and possibly as late as 2027—eighteen years after Progress customers began paying for the plant. Progress has estimated that by 2020, Levy-related expenses could add roughly $50 to the average residential customer's monthly bill.

The Levy plant's development appeared to take a step forward in December 2011 when the Nuclear Regulatory Commission approved its reactor design. But in February 2012, the Florida Public Service Commission approved a settlement agreement allowing Progress to suspend or cancel Levy's construction and recover $350 million from customers through 2017.

It is unclear whether Levy will ever be built. If the plant is canceled, Progress customers will have paid more than $1 billion in rates for no electricity generation, and Florida state law prohibits their recouping any portion of that investment. Such an outcome could help to deteriorate the political and regulatory climate in which Progress operates, which could ultimately impact credit ratings and shareholder value.

CWIP does nothing to actually reduce the risks associated with the projects it helps to finance. Construction cost overruns can and do still occur (see the text box about Progress Energy's Levy County nuclear power plant); O&M costs for the plant can still be unexpectedly high; anticipated customer load may not actually materialize; and so forth. What CWIP does is to reallocate part of the risk from utilities (and would-be bondholders) to customers. CWIP therefore provides utilities with both the incentive and the means to undertake a riskier investment than if CWIP were unavailable.

Regulators must be mindful of the implications of allowing a current return on CWIP, and should consider limiting its use to narrow circumstances and carefully drawn conditions of oversight. Regulators should also pay close attention to how thoroughly utility management has evaluated the risks associated with the projects for which it requests CWIP. Regardless of CWIP's other merits or faults, an important and too-often unacknowledged downside is that it can obscure a project's risk by shifting, not reducing, that risk.

Use of Rider Recovery Mechanisms. Another regulatory issue is the use by utilities of rate "riders" to collect investment or expenses. This practice speeds up cash flow for utilities, providing repayment of capital or expense outlays more rapidly than would traditional cost of service regulation. This allows utilities to begin collecting expenses and recovering capital without needing to capitalize carrying costs or file a rate case. Once again, regulators must consider whether these mechanisms could encourage a utility to undertake a project with higher risk, for the simple reason that cost recovery is assured even before the outlay is made.

Allowing a current return on CWIP, combined with revenue riders, is favored by many debt and equity analysts, who perceive these practices as generally beneficial to investors. And indeed, these mechanisms allow bondholders and stock owners to feel more assured of a return of their investment. And they might marginally reduce the utility's cost of debt and equity. But these mechanisms (which, again, transfer risk rather than actually reducing it) could create a "moral hazard" for utilities to undertake more risky investments. A utility might, for example, proceed with a costly construction project, enabled by CWIP financing, instead of pursuing market purchases of power or energy efficiency projects that would reduce or at least delay the need for the project. If negative financial consequences of such risky decisions extended beyond customers and reached investors, the resulting losses would be partially attributable the same risk-shifting mechanisms that analysts and investors originally perceived as beneficial.

Construction Cost Caps. Some regulatory agencies approve a utility's proposed infrastructure investments only after a cap is established for the amount of investment or expense that will be allowed in rates. Assuming the regulator sticks to the deal, this action will apportion the risk between consumers and investors. We wouldn't conclude that this actually reduces risk except in the sense that working under a cap might ensure that utility management stays focused on the project, avoiding lapses into mismanagement that would raise costs and likely strain relationships with regulators and stakeholders.

Rewarding Energy Efficiency. Another relevant regulatory practice concerns the treatment of demand-side resources like energy efficiency and demand response. It is well understood that the "throughput incentive" can work to keep a utility from giving proper consideration to energy efficiency; to the extent that a utility collects more than marginal costs in its unit price for electricity, selling more electricity builds the bottom line while selling less electricity hurts profitability. There are several adjustments regulation can make, from decoupling revenues from sales, to giving utilities expedited cost recovery and incentives for energy efficiency performance. Decoupling, which guarantees that a utility will recover its authorized fixed costs regardless of its sales volumes, is generally viewed by efficiency experts and advocates as a superior approach because it neutralizes the "throughput incentive" and enables utilities to dramatically scale up energy efficiency investment without threatening profitability. Ratings agencies view decoupling mechanisms as credit positive because they provide assurance of cost recovery, and Moody's recently observed "a marked reduction in a company's gross profit volatility in the years after implementing a decoupling type mechanism."[75] Whatever the chosen approach, the takeaway here is that without regulatory intervention, energy efficiency will not likely be accorded its correct role as a low cost and low risk strategy.[76]

Without regulatory intervention, energy efficiency will not likely be accorded its correct role as a low cost and low risk strategy.

4. USING FINANCIAL AND PHYSICAL HEDGES

Another method for limiting risk is the use of financial and physical hedges. These provide the utility an opportunity to lock in a price, thereby avoiding the risk of higher market prices later. Of course, this means the utility also foregoes the opportunity for a lower market price, while paying some premium to obtain this certainty.

Financial hedges are instruments such as puts, calls, and other options that a utility can purchase to limit its price exposure (e.g., for commodity fuels) to a certain profile. If the price of a commodity goes up, the call option pays off; if the price goes down, the put option pays off. Putting such a collar around risk is, of course, not free: the price of an option includes transaction costs plus a premium reflecting the instrument's value to the purchaser. Collectively these costs can be viewed as a type of insurance payment.

Another example of a financial hedge is a "temperature" hedge that can limit a utility's exposure to the natural gas price spikes that can accompany extreme weather conditions. A utility may contract with a counter-party so that, for an agreed price, the counter-party agrees to pay a utility if the number of heating-degree-days exceeds a certain level during a certain winter period. If the event never happens,

75 Moody's Investors Service, *Decoupling and 21st Century Rate Making* (New York: Moody's Investors Service, 2011), 4.

76 For a discussion of regulatory approaches to align utility incentives with energy efficiency investment, see Val Jensen, *Aligning Utility Incentives with Investment in Energy Efficiency*, ICF International (Washington, DC: National Action Plan for Energy Efficiency, 2007), http://www.epa.gov/cleanenergy/documents/suca/incentives.pdf.

Long-term Contracts for Natural Gas

In recent decades, utilities have mostly used financial instruments to hedge against volatile natural gas prices, and natural gas supply used for power generation has not been sold under long-term contracts. An exception is a recent long-term contract for natural gas purchased by Xcel Energy in Colorado. The gas will be used to fuel new combined cycle units that will replace coal generating units. The contract between Xcel Energy and Anadarko contained a formula for pricing that was independent of the market price of natural gas and runs for 10 years.

The long-term natural gas contract between Xcel Energy and Anadarko was made possible by a change in Colorado's regulatory law. For years, utilities and gas suppliers had expressed concern that a long-term contract, even if approved initially as prudent, might be subject to a reopened regulatory review if the price paid for gas under the contract was, at some future date, above the prevailing market price. Colorado regulators supported legislation making it clear in law that a finding of prudence at the outset of a contract would not be subject to future review if the contract price was later "out of the money." An exception to this protection would be misrepresentation by the contracting parties.

the utility forfeits the payment made for the hedge. If the event does happen, the utility might still need to purchase natural gas at an inflated price; even so, the hedge would pay off because it has reduced the company's total outlay. Simply stated, financial hedges can be used by a utility to preserve an expected value.

An illustration of a physical hedge would be when a utility purchases natural gas at a certain price and places it into storage. The cost of that commodity is now immune to future fluctuations in the market price. Of course, there is a cost to the utility for the storage, and the utility forgoes the possible advantage of a future lower price. But in this case the payment (storage cost) is justifiable because of the protection it affords against the risk of a price increase.

Long-term contracts can also serve to reduce risk. These instruments have been used for many years to hedge against price increases or supply interruptions for coal. Similarly, long-term contracts are used by utilities to lock in prices paid to independent power producers. Many power purchase agreements (PPAs) between distribution utilities and third party generators lock in the price of capacity, possibly with a mutually-agreed price escalator. But due to possible fuel price fluctuations (especially with natural gas), the fuel-based portion of the energy charge is not fixed in these contracts. So PPAs can shield utilities from some of the risks of owning the plants, but they do not hedge the most volatile portion of natural gas generation: the cost of fuel.

Regulated utilities and their regulators must come to an understanding about whether and how utilities will utilize these options to manage risk, since using them can foreclose an opportunity to enjoy lower prices.

5. HOLDING UTILITIES ACCOUNTABLE

From the market's perspective, one of the most important characteristics of a public utilities commission is its consistency. Consumers don't like surprises, and neither do investors. Financial analysts who rate regulatory climates across the states typically rank stability as one of the highest virtues for regulators. Indeed, this quality is often viewed to be as important as the absolute level of return on equity approved by a commission.

Consumers don't like surprises, and neither do investors. Financial analysts who rate regulatory climates across the states typically rank stability as one of the highest virtues for regulators.

Effective regulation—regulation that is consistent, predictable, forward-thinking and "risk-aware"—requires that regulators hold utilities accountable for their actions. Earlier, we stressed the value of regulators being actively involved in the utility resource planning process. But this tool works well only if regulators follow through—by requiring utilities to comply with the resource plan, to amend the resource plan if circumstances change, to live within an investment cap, to adhere to a construction schedule, and so forth. If the utility doesn't satisfy performance standards, regulatory action will be necessary.

This level of activity requires a significant commitment of resources by the regulatory agency. Utility resource acquisition plans typically span ten years or more, and a regulator must establish an oversight administrative structure that spans the terms of sitting commissioners in addition to clear expectations for the regulated companies and well-defined responsibilities for the regulatory staff.

6. OPERATING IN ACTIVE, "LEGISLATIVE" MODE

As every commissioner knows, public utility regulation requires regulators to exercise a combination of judicial and legislative duties. In "judicial mode," a regulator takes in evidence in formal settings, applies rules of evidence, and decides questions like the interpretation of a contract or the level of damages in a complaint case. In contrast, a regulator operating in "legislative mode" seeks to gather all information relevant to the inquiry at hand and to find solutions to future challenges. Judicial mode looks to the past, legislative mode

to the future. In his 1990 essay, former Ohio utilities regulator Ashley Brown put it this way:

> *Gathering and processing information is vastly different in judicial and legislative models. Legislating, when properly conducted, seeks the broadest data base possible. Information and opinions are received and/or sought, heard, and carefully analyzed. The process occurs at both formal (e.g., hearings) and informal (e.g., private conversation) levels. The goal is to provide the decision maker with as much information from as many perspectives as possible so that an informed decision can be made. Outside entities can enhance, but never be in a position to limit or preclude, the flow of information. The decision maker is free to be both a passive recipient of information and an active solicitor thereof. The latter is of particular importance in light of the fact that many of the interests affected by a decision are not likely to be present in the decision making forum.*[77]

Being a risk-aware regulator requires operating in legislative mode in regulatory proceedings, and especially in policy-making proceedings such as rulemakings. But the courts have also found that ratemaking is a proper legislative function of the states.[78] And since this state legislative authority is typically delegated by legislatures to state regulators, this means that, to some extent, regulators may exercise "legislative" initiative even in rate-setting cases.

In a recent set of essays, Scott Hempling, the former executive director of the National Regulatory Research Institute, contrasts regulatory and judicial functions and calls for active regulation to serve the public interest:

> *Courts and commissions do have commonalities. Both make decisions that bind parties. Both base decisions on evidentiary records created through adversarial truth-testing. Both exercise powers bounded by legislative line-drawing. But courts do not seek problems to solve; they wait for parties' complaints. In contrast, a commission's public interest mandate means it literally looks for trouble. Courts are confined to violations of law, but commissions are compelled to advance the public welfare.*[79]

Utility resource planning is one of the best examples of the need for a regulator to operate in legislative mode. When examining utilities' plans for acquiring new resources, regulators must seek to become as educated as possible. Up to a point, the more choices the better. The regulator should insist that the utility present and analyze multiple alternatives. These alternatives should be characterized fully, fairly, and without bias. The planning process should seek to discover as much as possible about future conditions, and the door should be opened to interveners of all stripes. Knowing all of the options—not simply the ones that the utility brings forward—is essential to making informed, risk-aware regulatory decisions.

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7. REFORM AND RE-INVENT RATEMAKING PRACTICES

It is increasingly clear that a set of forces is reshaping the electric utility business model. In addition to the substantial investment challenge discussed in this report, utilities are facing challenges from stricter environmental standards, growth in distributed generation, opportunities and challenges with the creation of a smarter grid, new load from electric vehicles, pressure to ramp up energy efficiency efforts—just to mention a few. As electric utilities change, regulators must be open to new ways of doing things, too.

77 Ashley Brown, "The Over-judicialization of Regulatory Decision Making," *Natural Resources and Environment* Vol. 5, No. 2 (Fall 1990), 15-16.

78 See, e.g., U.S. Supreme Court, *Munn vs. Illinois*, 94 U.S. 113 (1876), http://supreme.justia.com/cases/federal/us/94/113/case.html.

79 Scott Hempling, *Preside or Lead? The Attributes and Actions of Effective Regulators* (Silver Spring, MD: National Regulatory Research Institute, 2011), 22.

Today's energy industry faces disruptions similar to those experienced by the telecommunications industry over the past two decades. To deal with the digital revolution in telecommunications and the liberalization of those markets, regulators modernized their tools to include various types of incentive regulation, pricing flexibility, lessened regulation in some markets and a renewed emphasis on quality of service and customer education.

One area where electric utility regulators might profitably question existing practices is rate design. Costing and pricing decisions, especially for residential and small business customers, have remained virtually unchanged for decades. The experience in other industries (e.g., telecommunications, entertainment, music) shows that innovations in pricing are possible and acceptable to consumers. Existing pricing structures should be reviewed for the incentives they provide for customers and the outcomes they create for utilities.

The risk-aware regulator must be willing to think "way outside the box" when it comes to the techniques and strategies of effective regulation. Earlier we observed that effective regulators must be informed, active, consistent, curious and often courageous. These qualities will be essential for a regulator to constructively question status quo regulatory practice in the 21st century.

THE BENEFITS OF "RISK-AWARE REGULATION"

We have stressed throughout this report that effective utility regulators must undertake a lot of hard work and evolve beyond traditional practice to succeed in a world of changing energy services, evolving utility companies and consumer and environmental needs. What can regulators and utilities reasonably expect from all this effort? What's the payback if regulators actively practice "risk-aware regulation"?

- **FIRST**, there will be benefits to consumers. A risk-aware regulator is much less likely to enter major regulatory decisions that turn out wrong and hurt consumers. The most costly regulatory lapses over the decades have been approval of large investments that cost too much, failed to operate properly, or weren't needed once they were built. It's too late for any regulator to fix the problem once the resulting cost jolts consumers.
- **SECOND**, there will be benefits to regulated utilities. Risk aware regulation will create a more stable, predictable business environment for utilities and eliminate most regulatory surprises. It will be easier for these companies to plan for the longer-term. If regulators use a well-designed planning process, examining all options and assessing risks, utilities and their stakeholders will have greater reliance on the long-term effect of a decision.
- **THIRD**, investors will gain as well. Steering utilities away from costly mistakes, holding the companies responsible for their commitments and, most importantly, maintaining a consistent approach across the decades will be "credit-positive," reducing threats to cost-recovery. Ratings agencies will take notice, lowering the cost of debt, benefitting all stakeholders.
- **FOURTH**, governmental regulation itself will benefit. Active, risk-aware regulators will involve a wide range of stakeholders in the regulatory process, building support for the regulators' decision. Consistent, transparent, active regulation will help other state officials—governors and legislators—develop a clearer vision of the options for the state's energy economy.
- **FINALLY**, our entire society will benefit as utilities and their regulators develop a cleaner, smarter, more resilient electricity system. Regulation that faithfully considers all risks, including the future environmental risks of various utility investments, will help society spend its limited resources most productively. In other words, risk-aware regulation can improve the economic outcome of these large investments.

With two trillion dollars on the line, both the stakes and the potential benefits are high. If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Practicing risk-aware regulation will enable them to avoid expensive mistakes and identify the most important utility investments for realizing the promise of an advanced 21st century electricity system.

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APPENDIX 1:

UNDERSTANDING UTILITY FINANCE

MOST INVESTOR-OWNED UTILITIES (IOUS) IN THE UNITED STATES ARE IN A CONSTRUCTION CYCLE OWING TO THE NEED TO COMPLY WITH MORE STRINGENT AND EVOLVING ENVIRONMENTAL POLICIES AND TO IMPROVE AGING INFRASTRUCTURE. NEW INFRASTRUCTURE PROJECTS INCLUDE SMART GRID, NEW GENERATION AND TRANSMISSION. THE IOUS, THEREFORE, WILL BE LOOKING TO THE CAPITAL MARKETS TO HELP FINANCE THEIR RATHER LARGE CAPITAL EXPENDITURE PROGRAMS.

DEBT FINANCING

While the IOUs will be issuing some additional equity, a higher percentage of the new investment will be financed with debt. In general, utilities tend to be more leveraged than comparably-rated companies in other sectors (see the Rating Agencies section below). The electric utility sector's debt is primarily publicly issued bonds, including both first mortgage bonds (FMB) and senior unsecured bonds. While the utilities also issue preferred stock and hybrid debt securities, these instruments tend to represent a small portion of a company's capital structure. Non-recourse project finance is rare for utilities, but it is commonly used by unregulated affiliates.

Most regulated IOUs in the U.S. are owned by holding companies whose assets are primarily their equity interests in their respective subsidiaries. These operating company subsidiaries are typically wholly owned by the parent, so that all publicly-held stock is issued by the parent. Because most of these holding companies are quite large, the market for a holding company's stock is usually highly liquid.

In contrast to equity, bonds are issued by both the utility holding company and individual operating subsidiaries. Typically, holding and operating company bonds are non-recourse to affiliates. This means that each bond issuer within the corporate family will have its own credit profile that affects the price of the respective bonds. To illustrate this point, compare two American Electric Power subsidiaries, Ohio Power and Indiana Michigan. The companies have different regulators, generation mix, customer bases and, consequently, different senior unsecured Moody's bond ratings of Baa1 and Baa2, respectively. For this reason, each bond issuance of the corporate family trades somewhat independently.

Utility bonds trade in secondary markets and are traded over-the-counter rather than in exchanges like equities. For bond issuance of less than $300 million, the secondary market is illiquid and not very robust. Smaller utilities are frequently forced into the private placement market with their small issuances and accordingly pay higher interest rates compared to similarly-rated larger companies. Even if these smaller issues are placed in the public market, there is a premium for the expected lack of liquidity.

Secured debt in the form of FMBs is common in the electric utility sector. Such bonds are usually secured by an undivided lien on almost all of the assets of an operating utility. Bond documentation (called an "indenture") prohibits the issuance of such bonds in an amount that exceeds a specified percentage (usually in the range of 60 percent) of the asset value of the collateral. The maturities of these bonds are frequently as long as 30 years, and in rare occasions longer). While the lien on assets may limit a company's financing flexibility, the interest rate paid to investors is lower than for unsecured debt. The proceeds from FMBs are usually used to finance or refinance long-lived assets.

Senior unsecured bonds can be issued at any maturity, but terms of five and ten years are most common. These instruments are "junior" to FMBs, so that, in an event of default, these debt holders would be repaid only after the secured debt. But these bonds are "senior" to hybrids and preferred stock. In a bankruptcy, senior unsecured bonds are usually deemed equal in standing with trade obligations, such as unpaid fuel and material bills.

Utilities typically have "negative trade cycles," meaning that cash receipts tend to lag outlays. IOUs' short-term payables such as fuel purchases, salaries and employee benefits are due in a matter of days after the obligation is incurred. In contrast, the utility's largest short-term assets are usually customer receivables which are not due for 45—60 days after the gas or electricity is delivered. Therefore, utilities have short term cash needs referred to as "working capital" needs. To finance these short term needs utilities have bank credit lines and sometimes trade receivable facilities.

For larger utility corporate families, these bank lines can amount to billions of dollars. For example, American Electric Power has two large bank lines of $1.5 and $1.7 billion that mature in 2015 and 2016, respectively. AEP's lines and most of those of other utilities are revolving in nature. While termination dates typically range from one to five years for these lines, the utility usually pays down borrowings in a few months and accesses the line again when needed.

Interest on bank lines of credit is paid only when the lines are used, with a much lower fee paid on the unused portion of the lines. For financially weak utility companies, banks often require security for bank lines . But because utility operating companies are rarely rated below BBB-/Baa3, bank lines are, for the most part, unsecured.

Some larger utilities have receivable facilities in addition to revolving bank lines. The lender in a receivables facility usually purchases the customer receivables. There is an assumed interest expense in these transactions which is usually lower than the rate charged by banks for unsecured revolving lines.

Although preferred stock is a form of equity, it is usually purchased by a bond investor who is comfortable with the credit quality of the issuer and willing to take a junior position in order to get a higher return on its investment. There are also hybrid securities. Although they are technically debt instruments, they are so deeply subordinate and with such long repayment periods that investors and the rating agencies view these instruments much like equities. Frequently, hybrids allow the issuer to defer interest payments for a number of years. Some hybrids can be converted to equity at either the issuer's or investor's option.

S&P is the most rigorous of the rating agencies in treating the fixed component of power purchase agreements (PPA) as debt-like in nature. Also, some Wall Street analysts look at PPAs as liabilities with debt-like attributes. That being said, those analysts who do not consider PPAs as debt-like still incorporate in their analysis the credit implications of these frequently large obligations.

EQUITY FINANCING

In order to maintain debt ratings and the goodwill of fixed income investors, utility managers must finance some portion of their projects with equity. Managements are usually reluctant to go to market with large new stock issuances. Equity investors often see new stock as being dilutive to their interests, resulting in a decrease in the market price of the stock. But if a utility has a large capital expenditure program it may have no choice but to issue equity in order maintain its credit profile.

For more modest capital expenditure programs, a company may be able to rely on incremental increases to equity to maintain a desired debt to equity ratio. While the dividend payout ratios are high in this sector, they are rarely 100 percent, so that for most companies, equity increases, at least modestly, through retained earnings. Many companies issue equity in small incremental amounts every year to fulfill commitments to employee pension or rewards programs. Also, many utility holding companies offer their existing equity holders the opportunity to reinvest dividends in stock. For larger companies these programs can add $300 - $500 million annually in additional equity. Since these programs are incremental, stock prices are usually unaffected.

OTHER FINANCING

Project finance (PF) can also be used to fund capital expenditures. These instruments are usually asset-specific and non-recourse to the utility, so that the pricing is higher than traditional investment-grade utility debt. Project finance is usually used by financially weaker non-regulated power developers.

Some companies are looking to PF as a means of financing large projects so that risk to the utility is reduced. However, the potential of cost overruns, the long construction/development periods and use of new technology will make it hard to find PF financing for projects like new nuclear plants. This also applies to carbon capture/sequestration projects, as the technology is not seasoned enough for most PF investors. This means that, utilities may need to finance new nuclear and carbon capture/ sequestration projects using their existing balance sheets.

In order to reduce risk, a utility can pursue projects in partnership with other companies. Currently proposed large gas transport and electric transmission projects are being pursued by utility consortiums. Individual participants in gas transport projects in particular have used Master Limited Partnerships (MLPs) as a way to finance their interests. MLPs are owned by general and limited partners. Usually the general partner is the pipeline utility or a utility holding company. Limited partner units are sold to passive investors and are frequently traded on the same stock exchanges that list the parent company's common stock. One big difference between the MLP and an operating company is that earnings are not subject to corporate income tax. The unit holders pay personal income tax on the profits.

Companies have used both capital and operating lease structures to finance discrete projects, including power plants. The primary difference between an operating and capital lease is that the capital lease is reflected on the company's balance sheet. The commitment of the utility to the holder of the operating lease is deemed weaker. Most fixed income analysts, as well as the rating agencies, do not view these instruments as being materially different and treat operating leases for power plants as debt.

TYPICAL UTILITY INVESTORS

The largest buyers of utility equities and fixed income securities are large institutional investors such as insurance companies, mutual funds and pension plans. As of September 2011, 65 percent of utility equities were owned by institutions. While insurance companies and pension plans own utility equities, both trail mutual funds in the level of utility stock holdings. For example, the five largest holders of Exelon stock are mutual fund complexes.

Most retail investors own utility stock and bonds indirectly through mutual funds and 401k plans. But many individual investors also own utility equities directly, including utility employees. Small investors tend not to buy utility bonds because the secondary market in these instruments is rather illiquid, especially if the transaction size is small.

Common stock mutual funds with more conservative investment criteria are most interested in utility equities. While the market price of these stocks can vary, there is a very low probability of a catastrophic loss. Also, utility stocks usually have high levels of current income through dividend distributions. Another attractive attribute of these equities is that they are highly liquid. Essentially all utilities in the U.S. are owned by utility holding companies that issue common stock. Due to extensive consolidation in the sector over the past 20 years, these holding companies are large and have significant market capitalization. For these reasons, utility stocks are highly liquid and can be traded with limited transaction costs.

Utility fixed-income investments are far less liquid than equities. Thus, the typical bond investor holds onto the instruments much longer than the typical equity investor. Bonds are issued both by the utility holding company and individual operating subsidiaries. Because bonds are less liquid in the secondary market, investors in these instruments, such as pension plans and insurance companies, tend to have longer time horizons. Four of the top five investors in Exelon Corp bonds due 2035 are pension plans and insurance companies. Mutual bond funds tend to buy shorter-dated bonds.

The buyers of first mortgage bonds (FMBs) are frequently buy-and-hold investors. As FMBs are over-collateralized, bondholders are comfortable that they will be less affected by unforeseen negative credit events. It is not unusual for a large insurance company to buy a large piece of an FMB deal at issuance and hold it to maturity. Retail investors in utility bonds also tend to be buy-and-hold investors, as it is hard for them to divest their positions which are typically small compared to the large institutions. The relative illiquidity of utility bonds means that transaction costs can be high and greatly reduce the net proceeds from a sale.

Utility employees frequently own the stock of the companies for which they work. Employees with defined benefit pensions, however, are not large holders of utility stocks because pension plans hold little if any of an employer's stock owing to ERISA rules and prudent asset management practices. Mid-level non-unionized employees frequently have 401ks that are typically invested in mutual funds or similar instruments. However, it is not unusual for company matching of the employees' 401k contributions to be in company stock. Finally, senior management's incentive compensation is frequently paid in the company's common equity, in part to ensure that management's interests are aligned with those of the shareholders.

RATING AGENCIES

Most utilities have ratings from three rating agencies: Moody's Investors Services, Standard & Poor's Ratings Services, and Fitch Ratings. Having three ratings is unlike other sectors, which frequently use two ratings—Moody's or Standard & Poor's. Most utility bonds are held by large institutional investors who demand that issuers have at least Moody's and Standard & Poor's ratings.

Failing to have two ratings would cause investors to demand a very high premium on their investments, far more than the cost to utilities of paying the agencies to rate them. Having a third rating from Fitch usually slightly lowers the interest rate further. While investors have become less comfortable with the rating agencies' evaluations of structured finance transactions, this dissatisfaction has not carried over greatly into the corporate bond market, and especially not the utility bond market.

The agencies usually assign a rating for each company referred to as an *issuer rating*. They also rate specific debt issues, which may be higher or lower than the issuer rating. Typically a secured bond will have a higher rating than its issuer; preferred stock is assigned a lower rating than the issuer. Ratings range from AAA to D.[80] The "AAA" rating is reserved for entities that have virtually no probability of default. A "D" rating indicates that the company is in default.

The three agencies each take into account both the probability of default, as well as the prospects of recovery for the bond investor if there is a default. Utilities traditionally are considered to have high recovery prospects because they are asset-heavy companies. In other words, if liquidation were necessary, bond holders would be protected because their loans are backed by hard assets that could be sold to cover the debt. Further, the probability of default is low because utility rates are regulated, and regulators have frequently increased rates when utilities have encountered financial

80 Standard & Poor's and Fitch use the same ratings nomenclature. It was designed by Fitch and sold to S&P. For entities rated between AA and CCC the agencies break down each rating category further with a plus sign or a minus sign. For example, bonds in the BBB category can be rated BBB+, BBB and BBB-. Moody's ratings nomenclature is slightly different. The corresponding ratings in BBB category for Moody's are Baa1, Baa2 and Baa3. The agencies will also provide each rating with an outlook that is stable, positive or negative.

problems owing to events outside of companies' control. However, there are a few notable instances where commissions could not or would not raise rates to avoid defaults including the bankruptcies of Public Service of New Hampshire and Pacific Gas and Electric.

It is unusual for a utility operating company to have a non-investment grade rating (Non-IG, also referred to as high yield, speculative grade, or junk). Typically Non-IG ratings are the result of companies incurring sizable expenses for which regulators are not willing or able to give timely or adequate rate relief. Dropping below IG can be problematic for utilities because interest rates increase markedly. Large institutional investors have limited ability to purchase such bonds under the investment criteria set by their boards. Another problem with having an Non-IG rating is that the cost of hedging rises owing to increased collateral requirements as counterparties demand greater security from the weakened credit.

In developing their ratings, the agencies consider both quantitative and more subjective factors. The quantitative analysis tends to look at cash flow "coverage" of total debt and of annual fixed income payment obligations, as well as overall debt levels. In contrast, the typical equity analyst focuses on earnings. The rating agencies are less interested in the allowed returns granted by regulators than they are in the size of any rate decrease or increase and its effect on cash flow.

That said, the rating agency may look at allowed returns to evaluate the "quality" of regulation in a given state. All things being equal, they may give a higher rating to a company in a state with "constructive" regulation than to a company in a state with a less favorable regulatory climate. Constructive regulation to most rating agencies is where regulatory process is transparent and consistent across issuers in the state. Also, the agencies favor regulatory constructs that use forward-looking test years and timely recovery of prudently-incurred expenses. The agencies consider tracking mechanisms for fuel and purchased power costs as credit supportive because they help smooth out cash fluctuations. The agencies believe that while trackers result in periodic changes in rates for the customer, these mechanisms are preferable for consumers than the dramatic change in rates caused by fuel factors being lumped in with other expenses in a rate case.

Analysts also will look to see how utility managers interact with regulators. The agencies deem it a credit positive if management endeavors to develop construct relationships with regulators. The agencies may become concerned about the credit quality of a company if the state regulatory process becomes overly politicized. This may occur if a commission renders decisions with more of an eye toward making good press than applying appropriate utility regulatory standards. Politicized regulatory environments can also occur when a commission is professional and fair, but outside political forces, such as governors, attorneys general or legislators challenge a prudently decided case.

The rating agencies themselves can at times act as *de facto* regulators. Because utilities are more highly levered than most any other sector, interest expenses can be a significant part of a company's cost structure. Ratings affect interest rates. The agencies will look negatively at anything that increases event risk. The larger an undertaking, the greater the fallout if an unforeseen event undermines the project. A utility embarking on the development of a large facility like a large generation or transmission project, especially if is not preapproved by the regulators, might result in a heightened focus on the company by the agencies. The rating action could merely be change in outlook from stable to negative, which could in turn have a negative impact on the market price of outstanding bonds, interest rates on new issuances and even on equity prices. Many utility stock investors are conservative and pay more attention to rating agency comments and actions than investors with holdings in more speculative industries.

APPENDIX 2:

TOOLS IN THE IRP PROCESS

REGULATORS HAVE SEVERAL TOOLS AT THEIR DISPOSAL IN THE IRP PROCESS. ONE OF THE MOST IMPORTANT IS THE UTILITY REDISPATCH MODEL. THIS IS A COMPLEX COMPUTER PROGRAM THAT SIMULATES THE OPERATION OF A UTILITY'S SYSTEM UNDER INPUT ASSUMPTIONS PROVIDED BY THE USER. THE TERM "REDISPATCH" REFERS TO THE FACT THAT THE SOFTWARE MIMICS THE OPERATION OF AN ACTUAL UTILITY SYSTEM, "DISPATCHING" THE HYPOTHETICAL GENERATION RESOURCES AGAINST A MODEL LOAD SHAPE, OFTEN HOUR-BY-HOUR FOR MOST COMMONLY USED MODELS.

Three examples of these models are Prosym, licensed by Henwood Energy Services; Strategist, licensed by Ventyx; and GE MAPS, licensed by General Electric.

A model typically creates a 20- or 40-year future utility scenario, based on load projections provided by the user. The utility's energy and peak demand is projected for each hour of the time period, using known relationships about loads during different hours, days of the week and seasons of the year. The model then "dispatches" the most economic combination of existing or hypothetical new resources to meet the load in every hour of that time period.

The operating characteristics of each generating resource is specified as to its availability, fuel efficiency, fuel cost, maintenance schedule, and, in some models, its emissions profile. The resources available to the model will be a mixture of existing plants, taking note of their future retirement dates, plus any hypothetical new resources required by load growth. The model incorporates estimates of regional power purchases and their price, transmission paths and their constraints, fuel contracts, the retirement of existing facilities, etc.

In this way, the user of the model can test various combinations (scenarios) of proposed new generating plants, including base load plants, intermediate and peaking plants, intermittent renewable resources, etc. The model will calculate the utility's revenue requirement, fuel costs, and purchased power expenses in each scenario. The model might be used to estimate the cost of operating the system with a specific hypothetical portfolio, predict the level of emissions for a portfolio, measure the value of energy efficiency programs, test the relative value of different resources, measure the reliability of the system, etc.

The reader might analogize this modeling to "fantasy" baseball, where hypothetical teams play hypothetical games, yielding win-loss records, batting averages and pennant races.

As powerful as these modeling tools are, they are *production* models, first and foremost. As such, they are not particularly good at dealing with assumptions about energy efficiency and demand response. In using such models, the regulator must insist that the utility gives appropriate treatment to demand-side resources. It may be possible to re-work models to do this, or it may be necessary to conduct extra sensitivity analyses at varying levels of energy efficiency and demand response.

IRP SENSITIVITY ANALYSES

A redispatch modeling tool allows a utility and the regulator to test the resilience of portfolios against different possible futures. For example, a regulator might want to know how five different generation portfolios behave under situations of high natural gas prices, or tougher environmental regulations. By varying the input assumptions while monitoring the relevant output (e.g., net present value of future revenue requirements) the regulator can assess the risk that contending portfolios pose to future rates if, for example, fuel prices vary from their predicted levels.

To illustrate this idea, consider the following material from a case in Colorado. **Figure Appendix - 1** is a page excerpted from Xcel Energy's 2009 analysis in support of a resource plan filed before the Colorado Public Utilities Commission. The page shows the results of sensitivity analyses for the price of natural gas (high and low) and the cost of carbon emissions (high and low) for twelve different portfolios being considered by the Colorado PUC.

In all, the Colorado PUC studied 48 different generation portfolios in this IRP case. The portfolios differed based on how much natural gas generation was added, how much wind and solar generation was added, the schedule for closing some existing coal-fired power plants, the level of energy efficiency assumed, etc. (The actual generation units in each portfolio are not identified in this public document.

Figure Appendix - 1

EXAMPLE OF IRP SENSITIVITY ANALYSES

Base Scenario Assumption: High Efficiency, Medium Solar

Representative of Preferred Plan

Primary Scenario
High DSM (130% Goal)
Medium Section 123 (200 MW)
Base Load

Portfolios 1-12

Key Portfolio Characteristic		1	2	3	4	5	6	7	8	9	10	11	12
Portfolio Number		1	2	3	4	5	6	7	8	9	10	11	12
Portfolio Rank within Scenario (PVRR)		1	2	3	4	5	6	7	8	9	10	11	12
Wind (MW)													
Solar (MW)													
Intermittent (MW)													
Solar Storage (MW)													
Gas (MW)													
Other (MW)	1												
Total (MW)		1,872	1,902	1,907	1,932	1,977	1,966	1,911	1,860	1,936	2,039	1,982	2,078
Owned %													
Owned MW													
Total 123 (MW)													
CO2 (M ton)	2	26.8	26.7	26.8	26.7	26.6	26.8	26.8	26.8	26.9	26.6	26.5	26.6
% New Build	3												
Externalities	4	2	2	2	2	2	1	2	2	1	2	3	2
PVRR & Rank													
PVRR rank		1	2	3	4	5	6	7	8	9	10	11	12
PVRR ($M)	5	49,344	49,361	49,365	49,387	49,402	49,478	49,490	49,526	49,645	49,675	49,675	49,822
PVRR Delta ($M)	6	-	17	21	43	58	134	146	182	301	331	331	478
PV Rate ($/MWh)	7	71.87	71.90	71.90	71.94	71.96	72.07	72.09	72.14	72.31	72.36	72.36	72.57
CO2 Delta (M ton)	8	-	(0.30)	(0.02)	(0.50)	(0.68)	1.79	(0.09)	(0.04)	0.80	(0.57)	(0.81)	(0.65)
$10/ton CO2 Sensitivity													
PVRR rank	9	1	3	2	4	5	6	7	8	9	10	11	12
PVRR ($M)	5	43,695	43,722	43,716	43,758	43,786	43,805	43,845	43,877	43,981	44,054	44,080	44,203
Change ($M)	10	(5,649)	(5,638)	(5,649)	(5,628)	(5,616)	(5,673)	(5,645)	(5,649)	(5,664)	(5,622)	(5,596)	(5,619)
PVRR Delta ($M)	11	-	27	21	63	91	110	150	182	286	358	384	508
$40/ton CO2 Sensitivity													
PVRR rank	9	3	2	5	4	1	7	6	8	11	10	9	12
PVRR ($M)	5	60,066	60,061	60,087	60,067	60,056	60,247	60,204	60,250	60,392	60,311	60,285	60,451
Change ($M)	10	10,723	10,701	10,723	10,680	10,654	10,769	10,714	10,724	10,747	10,636	10,610	10,629
PVRR Delta ($M)	11	10	5	31	11	-	191	148	194	336	255	229	395
Low Gas Price Sensitivity													
PVRR rank	9	1	3	2	4	5	6	7	8	10	9	11	12
PVRR ($M)	5	47,935	47,959	47,956	47,992	48,016	48,055	48,075	48,118	48,234	48,230	48,318	48,371
Change ($M)	10	(1,409)	(1,402)	(1,409)	(1,395)	(1,386)	(1,423)	(1,415)	(1,407)	(1,411)	(1,445)	(1,357)	(1,451)
PVRR Delta ($M)	11	-	24	22	57	81	121	140	184	299	295	383	436
High Gas Price Sensitivity													
PVRR rank	9	5	4	6	3	1	7	8	10	9	11	2	12
PVRR ($M)	5	57,122	57,091	57,144	57,070	57,025	57,295	57,326	58,234	57,421	58,268	57,059	58,464
Change ($M)	10	7,778	7,730	7,780	7,684	7,623	7,817	7,836	8,708	7,776	8,593	7,384	8,642
PVRR Delta ($M)	11	97	66	120	46	-	270	302	1,209	396	1,244	34	1,439

Otherwise, it would have created problems for the competitive bidding process used to award contracts to supply the power to the utility.)

Each column in the table represents a different portfolio, numbered 1 to 12. Portfolio 2 is the Xcel's preferred plan. The rows show the modeling results for each portfolio. For example, the Present Value of Revenue Requirements (PVRR) is calculated for each portfolio and is shown the line indicated by the first PVRR arrow, along with the ranking of that portfolio. The lower half of the chart shows the cost of each portfolio under different assumptions about the cost of carbon emissions (higher or lower than base case predictions) and for natural gas prices (higher or lower than base case predictions).

CAVEATS

Models are a terrific way to keep track of all the moving parts in the operation of a utility portfolio. But it is one thing to know that each resource has certain operating characteristics; it is quite another to see these qualities interact with each other in dynamic fashion. And while utility modeling tools, such as production cost models can be helpful, care must be taken with their use.

Obviously the models are helpful only to the extent that the inputs are reasonable and cover the range of possibilities the regulator wishes to examine. Load forecast must be developed with care; assumptions about future fuel costs are really educated guesses, and should be bracketed with ranges of sensitivity.

Because there are so many possible combinations, variations and sensitivities, the regulator in an IRP case must make a decision early in the process about the scope of the portfolios to be examined. The utility should be directed to analyze and present all scenarios requested by the regulator, together with any portfolios preferred by the utility.

Finally, the model's best use is to inform judgment, not substitute for it. The amount of data produced by models can be overwhelming and may give a false sense of accuracy. The risk-aware regulator will always understand the fundamental uncertainties that accompany projections of customer demand, future fuel costs and future environmental requirements.

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PJM's Evolving Resource Mix and System Reliability

PJM Interconnection
March 30, 2017

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Contents

Prologue

Beginning in 2015, PJM Interconnection has produced a series of papers examining how aspects of its operations, planning and markets could and should evolve given the changing landscape of the electric power industry. On October 12, 2015, PJM produced a paper entitled "Virtual Transactions in the PJM Energy Markets"[1] recommending enhancements to the mechanisms by which virtual transactions occur in the PJM markets. On May 6, 2016, PJM published its paper "Resource Investment in Competitive Markets," [2] in which PJM compared the efficiency of resource entry and exit in competitive and traditionally-regulated environments.

This paper, the latest in the series of work products, evaluates the changing resource mix in PJM given environmental regulations, the preponderance of low-cost natural gas, the increasing penetration of renewable resources and demand response, and the potential for retirements of nuclear power resources. Specifically, the paper examines whether the resource attributes necessary to maintain system reliability will continue to be available in sufficient quantities within various potential future resource portfolios. In addition, the paper raises questions about whether PJM should evaluate operating and planning for potential system events beyond those that drive traditional reliability criteria. More specifically, the paper questions whether there are additional objectives for system resilience that could be achieved by enhancing operational and planning procedures and requirements while taking into account actions PJM already has taken, such as implementation of Capacity Performance.

PJM will focus on additional subject areas associated with the evolving electricity industry as part of separate, future efforts. This paper does not explore, for example, the economics of any particular resource type, the growing trends around the desires of states to subsidize certain resources or resource types to ensure their continued operation, nor the impacts of such subsidies on wholesale markets. This paper also does not address the future evolution of the planning process with respect to whether and how the transmission planning process should include system resilience as a criteria and/or a driver of the need for additional system infrastructure. Finally, this paper does not address any specific areas involved with the evolution of how prices are formed in the capacity, energy or ancillary service markets. PJM will continue to focus on these subjects and will produce additional work products.

This current paper integrates into the context of the other subject areas by answering questions concerning whether the evolving resource mix is resulting in a loss of diversity that will lead to future reliability problems. Acting FERC Chairman Cheryl LaFleur[3] commented at the FERC technical conference following the 2014 polar vortex:

> *The second big thing that all of a sudden everyone is asking about the markets just in the last to 24 months is what about fuel diversity? What about fuel diversity? Well the markets have a single clearing price product. That's how they were set up. They were not set up to buy tranches of this and tranches of that. But if there are elements of what the baseload product resources provide that are being under-valued in the market that need to somehow use the market to try to solve that, I think that also is well worth the effort. Because it seems we are hearing a consistent theme that there is something that is being under-valued when we just go to the short term gas lowest price, and I urge you. We will work with you on that…*

1 http://www.pjm.com/~/media/committees-groups/committees/mc/20151019-webinar/20151019-item-02-virtual-transactions-in-the-pjm-energy-markets-whitepaper.ashx

2 PJM Value of Markets Paper - http://www.pjm.com/~/media/about-pjm/newsroom/2016-releases/20160506-pjm-posts-value-of-markets.ashx

3 Federal Energy Regulatory Commission Technical Conference on April 1, 2014

The paper represents PJM's effort to understand fuel diversity and its impact to reliability. This paper also presents additional questions to be investigated with respect to operating and planning for certain components of system resilience. Further work is required to complete the picture of how PJM's operations, planning and markets should continue to evolve to address these other issues. PJM looks forward to engaging with members, regulators and other stakeholders on these important issues going forward.

Executive Summary

Introduction

Recent growth in the amount of natural gas-fired and renewable generation has raised questions about "fuel diversity" on the PJM Interconnection system. Considering the retirement of coal-fired generation and to a lesser extent the threat of nuclear generation retirement, stakeholders have questioned whether the system is losing too many resources which historically have been referred to as "base load"[4] generation capability and whether the system is – or could become – so dependent on natural gas or renewable resources that operational reliability is adversely impacted. In response to those concerns, PJM conducted this analysis to evaluate fuel diversity through the lens of reliability and to identify a range of resource mixes that effectively manage reliability risk.

This paper does not analyze market or economic impacts of fuel diversity, nor does it address public policy issues, such as environmental or job impacts of different resource mixes. The paper's focus is on the reliability aspects of fuel mix diversity, including fuel security. The paper offers insight, from a grid operator's perspective, for policymakers to consider when assessing the impacts of a changing resource mix and poses questions about new impacts to evaluate.

Approach and Risk Analysis

In light of the increasing contribution of natural gas-fired generation and retirement of coal-fired generation, PJM has undertaken several natural gas analyses to assess potential system reliability implications. All the studies generally concluded that the existing and planned natural gas pipeline infrastructure would be adequate for current and future anticipated electric system needs.[5]

Today's resource profile in PJM is both reliable[6] and diverse – with a combination of natural gas, coal, nuclear, renewables, demand response and other resource types. Historical events discussed in this paper highlight that a more diverse system is more likely to have increased flexibility and adaptability to (1) mitigate the risk associated with equipment design issues or common modes of failure[7] in similar resource types, (2) address fuel price volatility and fuel supply disruptions and (3) reliably mitigate risk caused by weather and other unforeseen system shocks. In this way, resource diversity can be considered a system-wide hedging tool that helps ensure a steady, reliable supply of electricity.

PJM's assessment of the reliability services provided by different resource types builds upon work initiated by the North American Electric Reliability Corporation (NERC) and the power industry to define "essential reliability services," which comprise a subset of generator reliability attributes. Key generator reliability attributes defined and analyzed as part of this paper include frequency response, voltage control, ramp, fuel assurance, flexibility, black start, environmental restrictions and equivalent availability factor.[8]

[4] In this paper, "base load" generation refers to units that typically do not cycle due to unit limitations or market economics.

[5] U.S. Department of Energy Report: Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector, https://energy.gov/sites/prod/files/2015/02/f19/DOE%20Report%20Natural%20Gas%20Infrastructure%20V_02-02.pdf

[6] See the definition of reliability at the beginning of the Background section in this paper.

[7] A common mode failure is one event that causes multiple systems or system components to fail.

[8] See the Defining Generator Reliability Attributes section of this paper for the definition of these terms.

PJM analyzed each resource type's ability to provide generator reliability attributes based on the resource type's physical capabilities and PJM's operational experience. For the expected near-term resource portfolio[9] and future portfolios,[10] PJM calculated the capability of each resource type to provide reliability services as well as the total amount of each reliability attribute available in different resource portfolios. Each potential future portfolio was assessed based on its ability to provide two components of reliability: resource adequacy and operational reliability.

Resource adequacy addresses the amount of capacity needed to serve a forecasted peak load while meeting the required Loss of Load Expectation[11] (LOLE) criterion.[12] To ensure resource adequacy, each potential portfolio was tested against the LOLE criterion. The portfolios were subjected to a second LOLE test to account for intermittent output from wind and solar resources and currently limited storage capabilities. This second test ensured that portfolios with large unforced capacity shares of intermittent resource were able to serve load during hours that their outputs would be significantly lower than their capacity obligations. Portfolios that failed the second LOLE test were considered "infeasible."

Operational reliability addresses the grid's day-to-day operational needs and is measured by a portfolio's capability to provide the defined key generator reliability attributes. To assess operational reliability, PJM created a "composite reliability index" using the calculated capability of each resource type to provide the generator reliability attributes. The analysis used the index 1) to identify portfolios at risk of failing to provide adequate levels of the key generator reliability attributes and 2) to quantify and assess the reliability of a given potential resource portfolio across four operational states (i.e., normal peak conditions, light load, extremely hot weather and extremely cold weather). Portfolios with the lowest composite reliability indices were deemed "at risk" for underperformance in terms of providing the defined key generator reliability attributes. These portfolios do not exhibit, or only partially exhibit, numerous generator reliability attributes in one or more of the studied operational states.

The paper does not identify all possible feasible resource mixes, nor does it define an optimal mix. Rather, the analysis used this risk assessment to evaluate a range of potential resource portfolios based on their abilities to provide generator reliability attributes benchmarked against the generator reliability attribute capability of the expected near-term portfolio.

Summary of Analysis Results

Among the key findings of the analysis:

- The expected near-term resource portfolio is among the highest-performing portfolios and is well equipped[13] to provide the generator reliability attributes.

[9] The expected near-term PJM resource portfolio was established by projecting the composition of the generation mix in PJM out to 2021. The projection reflects near-term trends in announced generator deactivations and added capacity from the PJM Generation Interconnection Queues. More detail on this approach is in the Appendix.

[10] The analysis used recent trends in PJM's generator interconnection queues and deactivation announcements to develop 360 potential future portfolios. More detail on this approach is in the Appendix.

[11] The LOLE criterion defines the adequacy of capacity for the entire PJM footprint so that there are sufficient capacity resources to ensure, load exceeds available capacity, on average, only once in 10 years.

[12] See Federal Energy Regulatory Commission Order 747 – https://www.ferc.gov/whats-new/comm-meet/2011/031711/E-7.pdf

[13] Based on the requirements of the PJM Open Access Transmission Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement and applicable NERC reliability standards

- As the potential future resource mix moves in the direction of less coal and nuclear generation, generator reliability attributes of frequency response, reactive capability and fuel assurance decrease, but flexibility and ramping attributes increase.
- A marked decrease in operational reliability was observed for portfolios with significantly increased amounts of wind and solar capacity (compared to the expected near-term resource portfolio), suggesting de facto performance-based upper bounds on the percent of system capacity from these resource types. Additionally, most portfolios with solar unforced capacity[14] shares of 20 percent or greater were classified infeasible because they resulted in LOLE criterion violations at night. Nevertheless, PJM could maintain reliability with unprecedented levels of wind and solar resources, assuming a portfolio of other resources that provides a sufficient amount of reliability services.
- Portfolios composed of up to 86 percent natural gas-fired resources maintained operational reliability.[15] Thus, this analysis did not identify an upper bound for natural gas. However, additional risks, such as gas deliverability during polar vortex-type conditions and uncertainties associated with economics and public policy, were not fully captured in this analysis. Risks with respect to natural gas may lie not in capability to provide the generator reliability attributes but rather in these other uncertainties.
- More diverse portfolios are not necessarily more reliable; rather, there are resource blends between the most diverse and least diverse portfolios which provide the most generator reliability attributes.

Fuel Security and Resilience[16]

The analysis discussed in this paper was initiated by questions about "fuel diversity" on the PJM system and whether the system could become so dependent on natural gas or renewable resources that operational reliability would be adversely impacted. Fuel diversity itself does not ensure reliability. According to the results of PJM's analysis reported in this paper, the composition of a resource portfolio could negatively impact that portfolio's ability to provide an appropriate level of generator reliability attributes. The adequate level of fuel diversity allows increased flexibility and adaptability.

Nevertheless, the analysis shows that many of the potential future resource portfolios are likely to be reliable because they are likely to provide adequate amounts of the defined key generator reliability attributes. This observation holds true even for potential resource mixes that are heavily reliant on natural gas-fired generation and thus lack fuel diversity. For the purpose of this paper, the terms fuel security and energy security can be used interchangeably. (In addition, as mentioned previously, this paper does not focus on the economic impact of fuel security.)

"Heavy" reliance on one resource type, such as a resource portfolio composed of 86 percent natural gas-fired resources, however, raises questions about electric system resilience, which are beyond the reliability questions this paper sought to

[14] Unforced capacity (UCAP) is installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating; it is calculated for each generation Capacity Resource based on EFORd data for the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit. Manual 18: PJM Capacity Market, Attachment A: Glossary of Terms, Revision 36, Effective Date: 12/22/2016.

[15] The potential 86-percent-natural-gas portfolio would occur if all the coal and nuclear resources in the expected near-term portfolio retired and were replaced exclusively by natural gas. Portfolios composed of natural gas unforced capacity shares greater than 86 percent were not considered in the analysis because there is no reasonable expectation that any such portfolios could actually materialize.

[16] Resilience, in the context of the bulk electric system, relates to preparing for, operating through and recovering from a high-impact, low-frequency event. Resilience is remaining reliable even during these events.

address. Resilience is the capability of an energy system to tolerate disturbance and to continue to deliver energy services to consumers. Relying too heavily on any one fuel type may negatively impact resilience because resources do not provide generator reliability attributes equally. External drivers have impacted and could continue to impact the resource mix.

Moving Forward

The capability of resource types to provide various generator reliability attributes may change in the future because of changes in technology or regulations. Therefore, operations, market compensation and regulatory structures may need to shift to ensure that adequate levels of generator reliability attributes are maintained in future resource mixes. PJM will need to assess diversity and security going forward and work through either existing processes and market enhancements or develop new solutions to ensure that sufficient generator reliability attributes will be available.

PJM and its stakeholders should continue to examine resilience-related low-probability and high-impact events which can cause significant reliability impacts. PJM will continue to identify the highest risks to reliability from the anticipated resource mix changes to determine potential techniques to identify and mitigate natural gas infrastructure vulnerabilities – given the current and expected rapid growth in natural gas generation. Although each resource type carries with it sizable exposure to low-probability high-impact events, the ever-growing increase of natural gas as a fuel source makes continued examination of dependence on natural gas particularly appropriate. PJM also will continue to identify means to mitigate the exposure to “realistic” interruption events, which are not extreme but part of the daily physical or political landscape.

However, unlike the reliability services used in this analysis, criteria for resilience are not explicitly defined or quantified today. Some questions PJM and its stakeholders should consider include:

- Does PJM’s current set of business practices ensure that PJM’s evolving resource mix will result in continued reliable operations?
    - Are there reliability attributes that are missing from this analysis, and what, if any, generator reliability attributes are important but currently being undervalued in PJM?
    - During high-dependency / high-risk periods, should PJM schedule the system differently to consider fuel security concerns?
    - How can distributed energy resources and renewable resources provide additional reliability or resilience services through, for example, advances in inverter and storage technologies?
- How could PJM’s business practices include resilience?
    - Should PJM plan for and operate to a set of extreme contingencies that maintain an adequate operating margin under normal operations? Extraordinary situations?
    - Should PJM and the natural gas pipelines coordinate, study and operate to joint electric and natural gas contingencies?[17]
    - Could black-start requirements and restoration strategy better consider resilience, for example, in how PJM defines black-start resources, critical load and requirements for cranking paths?

PJM’s established planning, operations and markets functions have resulted in a PJM resource mix that is reliable. The current resource mix is also diverse.[18] PJM recognizes that the benefits of fuel mix diversity include the ability to withstand

[17] http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Reccommendations_Board_Approved_Nov_2016.pdf

equipment design issues or common modes of failure in similar resource types, fuel price volatility, fuel supply disruptions and other unforeseen system shocks. PJM will continue to leverage the proven approach of the well-developed stakeholder process both to ensure future resource mixes support continued reliable operations and to further define criteria for resilience.

[18] http://www.pjm.com/markets-and-operations.aspx

Background

Recent growth in the share of generation fueled by natural gas and renewables has raised questions about "fuel diversity" on PJM Interconnection system. Considering the retirement of coal-fired generation and to a lesser extent the potential threat of nuclear generation retirement, stakeholders have questioned whether the system is losing too many resources which historically have been referred to as "base load"[19] generation capability and whether the system is – or could become – so dependent on natural gas or renewable resources that reliability would be adversely impacted. Many have attempted to define fuel diversity through economic and political lenses. This paper analyzes fuel diversity through a reliability lens to identify the risks associated with a range of potential resource mix portfolios.

The electricity resource mix has shifted throughout PJM's history, and the PJM system has proven reliable in the face of change. Adequacy and security are two key aspects of reliability.[20] The PJM planning process and Capacity Market maintain resource adequacy by ensuring sufficient resources to meet demand under extreme conditions. Security is maintained by operating the system in a way that anticipates the possibility of failure of key system elements in order to minimize the loss of service to large groups of customers.[21] While effective transmission planning is an integral aspect of reliability, it is not in the scope of this paper. Rather this paper focuses on supply resources, and their operational attributes that contribute to system reliability.

Fuel diversity in the electric system generally is defined as utilizing multiple resource types to meet demand. A more diversified system is intuitively expected to have increased flexibility and adaptability to: 1) mitigate risk associated with equipment design issues or common modes of failure in similar resource types, 2) address fuel price volatility and fuel supply disruptions, and 3) reliably mitigate instabilities caused by weather and other unforeseen system shocks.[22] In this way, fuel diversity can be considered a system-wide hedging tool that helps ensure a stable, reliable supply of electricity.

Diversity often is a mechanism to enhance energy security, which is defined as "the uninterrupted availability of energy sources at an affordable price."[23] The International Energy Agency notes the temporal context of energy security:

> *Long-term energy security mainly deals with timely investments to supply energy in line with economic developments and sustainable environmental needs. Short-term energy security focuses on the ability of the energy system to react promptly to sudden changes within the supply-demand balance. Lack of energy security is thus linked to the negative economic and social impacts of either physical unavailability of energy, or prices that are not competitive or are overly volatile.*

The concept of diversity spans many industry sectors. In any application, diversity consists of three basic properties: variety, balance and disparity.[24] As each of these properties increase, diversity also increases. This paper adapted these properties to describe PJM's view of electric system diversity:

[19] In this paper, "base load" generation refers to units that typically do not cycle due to unit limitations or market economics.

[20] https://learn.pjm.com/Media/about-pjm/newsroom/fact-sheets/reliability-fact-sheet.pdf

[21] PJM operators make adjustments in real time so that the system is prepared and protected in the event of a sudden, unexpected disturbance or failure.

[22] Examples of system shocks are described in the Historical Events that Demonstrate the Importance of System Diversity section and in the Appendix.

[23] International Energy Agency. https://www.iea.org/publications/freepublications/publication/moses_paper.pdf

[24] Stirling, Andy. (2008). *Chapter 1 - Diversity and Sustainable Energy Transitions: Multicriteria Diversity Analysis of Electricity Portfolios.* Analytical Methods for Energy Diversity & Security, Elsevier Global Energy Policy and Economics Series.

- Variety is a measure of how many different resource types are on the system. A system with more resource types in its generation mix has greater variety.
- Balance is a measure of how much grid operators rely on certain resource types. Balance increases as the reliance on different resource types in a generation mix is becoming more evenly distributed.
- Disparity is a measure of the degree of difference among the resource types relative to each other. Disparity can relate to the geographic distribution of resource types – generation resources that are evenly distributed across the system are more disparate than concentrated pockets of generation resources. Disparity also relates to operational characteristics of resources – a system with resource types that have different operational characteristics is more disparate than a system in which all of the resource types have similar operational characteristics.

Diversity of the PJM System

PJM has a variety of different resource types in its diverse resource mix. For the purposes of this paper, PJM grouped resources into 11 classifications [25] (Coal, natural gas steam, natural gas combustion turbine, oil steam, oil combustion turbine, nuclear, solar, wind, hydro, battery/storage, and demand response).

The resource mix within PJM has become more evenly balanced over time. In 2005, coal and nuclear resources generated 91 percent of the electricity on the PJM system.[26] Over time, policy initiatives, technology improvements, and economics spurred a shift from coal to natural gas and renewable generation. From 2010 to 2016 in PJM, coal-fired units made up 79 percent of the megawatts retired,[27] and natural gas and renewables made up 87 percent of new megawatts placed in service.[28] PJM's installed capacity in 2016 consisted of 33 percent coal, 33 percent natural gas, 18 percent nuclear, and 6 percent renewables (including hydro).[29]

Trends in the PJM Capacity Market suggest that shifts in the resource mix will continue to occur (Figure 1).

[25] The analysis grouped units by majority fuel types, and as such, may not exclusively represent every type or combination of fuel, prime mover and technology type.

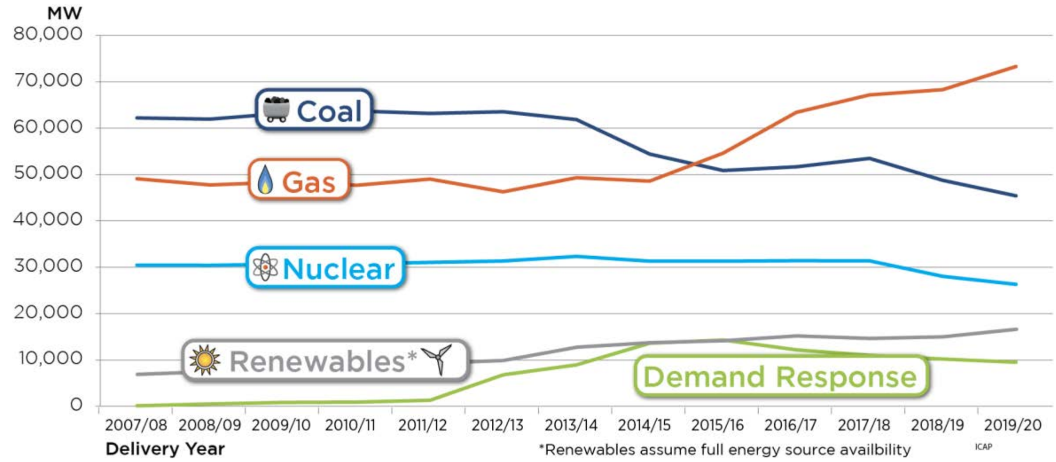
[26] PJM GATS System Mix - https://gats.pjm-eis.com/gats2/PublicReports/PJMSystemMix

[27] PJM Generation Deactivation data; posted at http://www.pjm.com/planning/generation-deactivation/gd-summaries.aspx

[28] PJM Generation Queues (http://www.pjm.com/planning/generation-interconnection/generation-queue-active.aspx). Queue project megawatts are based on "MW placed in service" with Status Codes of IS, UC-ISP, or Active-ISP. MW in service represents the new generation capability added to the system; actual capacity interconnection rights may be lower based on limitations for certain fuel types or rights as specified in individual interconnection agreements.

[29] PJM Capacity by Fuel Type 2016 - http://www.pjm.com/~/media/markets-ops/ops-analysis/capacity-by-fuel-type-2016.ashx ; 'Renewables' is inclusive of Hydro.

Figure 1. PJM Cleared Installed Capacity by Delivery Year

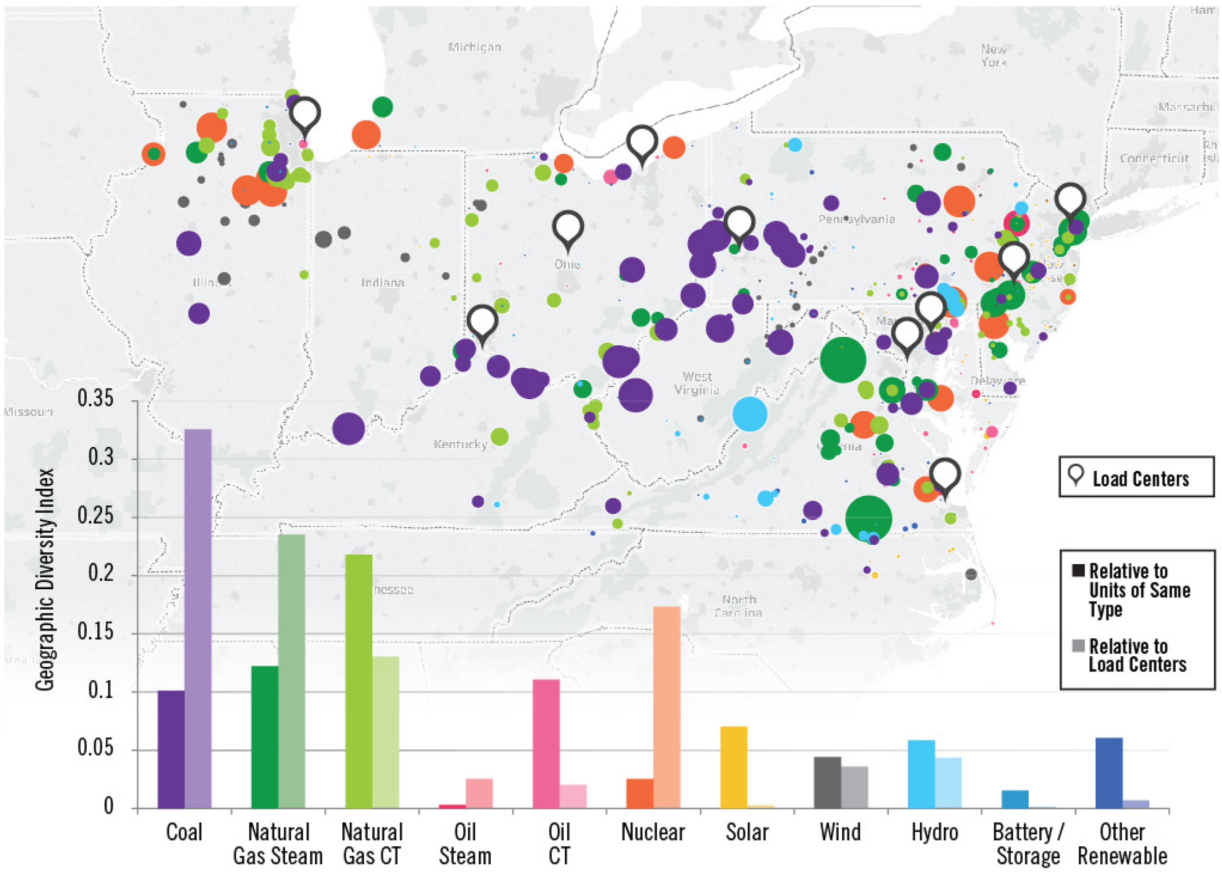


The disparity among PJM resource types can be grouped into two main categories: geographic and operational characteristics. PJM's geographic diversity has increased as the PJM footprint expanded. Figure 2 depicts the geographic diversity of the different resource types in PJM. The geographic diversity indices[30] capture the dispersion of units of the same resource type and the distance of a resource type from load centers.[31] Coal units have a low index relative to each other because they tend to be clustered near fuel sources, while at the same time have a high index relative to load because they tend to be far from load centers. In contrast, natural gas and oil combustion turbines (CTs) tend to be dispersed relative to each other, but close to the load centers. Geographic diversity can act as a system wide hedge to reduce potential reliability impacts of local supply/infrastructure disruptions by leveraging resources across the footprint.

[30] The geographic diversity index titled "Relative to Units of Same Resource Type" was calculated using MW weighted distances between units of the same resource type. The geographic diversity index titled "Relative to Load Centers" was calculated using MW weighted and load weighted distances between units of the same resource type and the load centers.

[31] Loads for the top ten metropolitan areas in the PJM footprint are assumed to be proportional to the 2016 Gross Metro Product (GMP) shares of those areas.

Figure 2. Geographic Diversity[32]

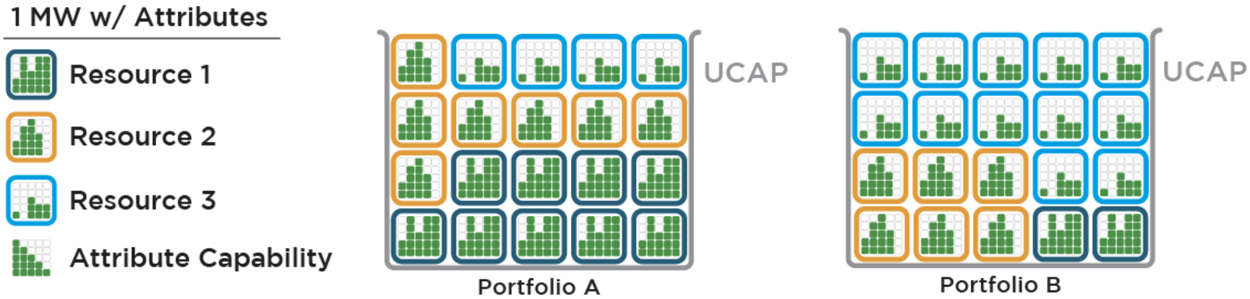


A disparate mix of resource types has different operational characteristics that aid in maintaining system reliability. In this paper, these operational characteristics are referred to as generator reliability attributes. A benefit of diversity is having the ability to leverage the capabilities of different resources types when they are most needed. However, not all resource types are equal in their ability to provide generator reliability attributes necessary for system operation, or in their ability to be resilient during times of system stress.[33] Figure 3 illustrates how the generator reliability attributes of different resource types and the shares of these resource types in a portfolio impact the total amount of generator reliability attribute capability. Each resource in Figure 3 has different generator reliability attribute capabilities. Differences in generator reliability attribute capabilities, and the resource mix in each portfolio, result in Portfolio B having less total capability to provide generator reliability attributes than Portfolio A.

[32] Loads for the top ten metropolitan areas in the PJM footprint are assumed to be proportional to the 2016 Gross Metro Product (GMP) shares of those areas.

[33] The Generator Reliability Attributes will be discussed in detail in the Reliability section.

Figure 3. Generator Reliability Attribute Primer

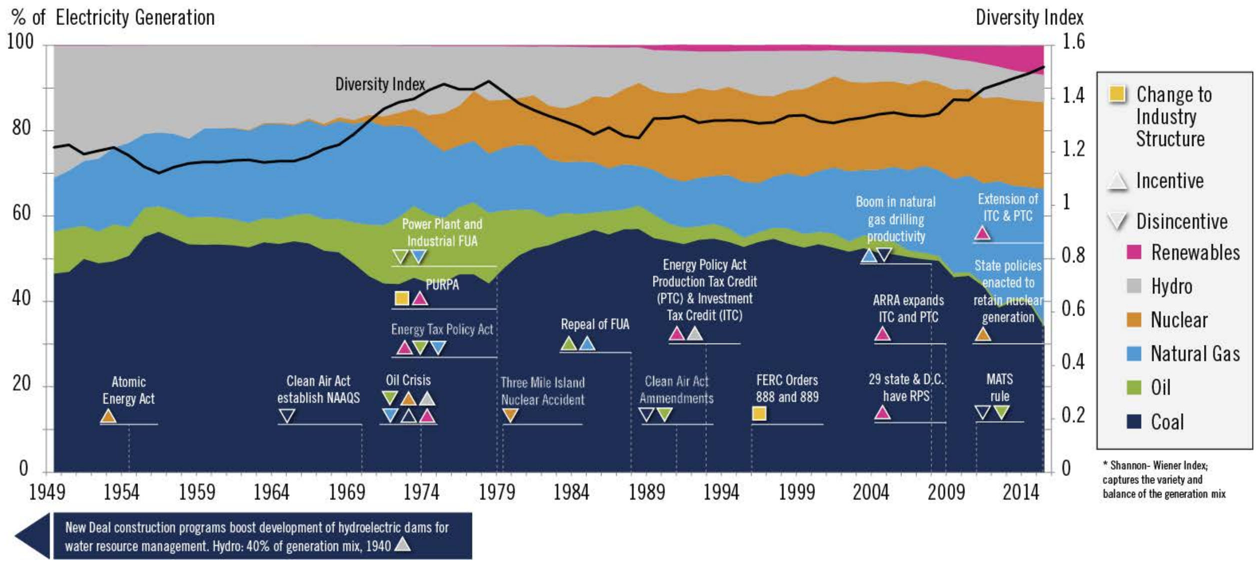


Historical Drivers of Fuel Diversity in the United States

Historical drivers of resource mix change are an important part of understanding fuel diversity issues. The evolution of the resource mix in the United States is a product of technological development, economics, government policy and geopolitical forces. Figure 4 relates key historic drivers of the shifting composition and relative diversity of the U.S. resource mix.[34] Policy drivers often target specific resource types. Many of these drivers influence both fuel diversity itself, and create additional drivers. For example, tax incentives and state Renewable Portfolio Standards increased the amount of renewable resources. The increased demand for renewables resulted in more research and development to reduce manufacturing costs and increase unit efficiency, making renewable resource development more viable.

[34] The Diversity Index was calculated as a Shannon-Wiener Index. This accounts for number generation resources in each year, and the share of those resources in the fleet, and show the relative diversity of the generation mix in each year.

Figure 4. Generation Mix Driver Timeline



NOTE: This graphic is not an exhaustive representation of all drivers related generation mix change. The intent was to capture examples of major drivers, with a focus on policies and events that targeted specific resource types.			
NAAQS	National Ambient Air Quality Standards	ARRA	American Recovery & Investment Act
PURPA	Public Utility Regulatory Policies Act of 1978	RPS	Renewable Portfolio Standard
FUA	Power Plant and Industrial Fuel Use Act of 1978	MATS	Mercury and Air Toxics Standards

Exploring fuel diversity from a historical perspective makes clear that "the only thing constant is change."[35] Policies have and will continue to incent or dis-incent specific fuel types depending on the economic, geopolitical, or social climate at that time. The maintenance of national energy security has and will continue to be an important policy driver. PJM must prepare and adjust as these policies continue to directly impact the composition of the resource mix.

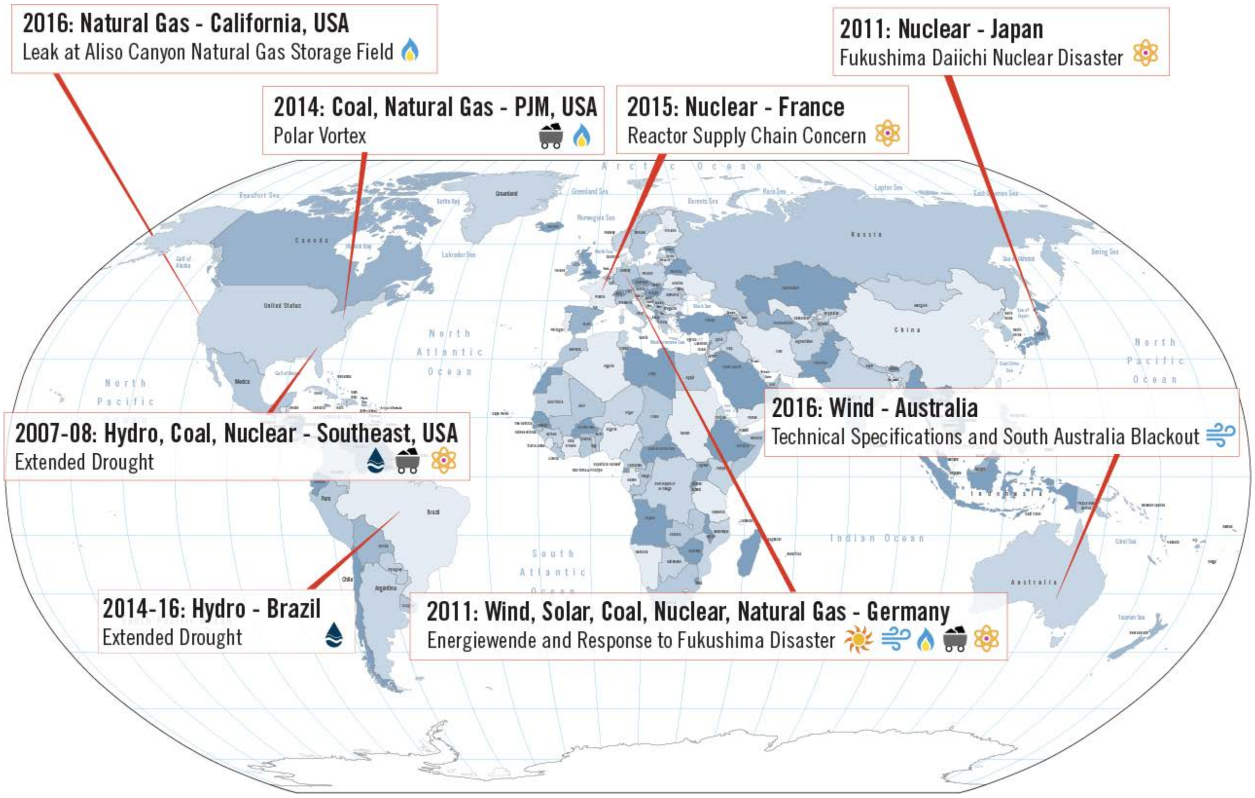
Historical Events that Demonstrate the Importance of System Diversity

Global events emphasize the importance of assessing the risks associated with current or future resource mixes. All resource types are susceptible to issues that could compromise reliability and fuel security. Figure 5 provides examples of historical events that exposed the risks associated with different resource types.[36] These events were caused by natural occurrences, such as extreme weather events, and unforeseen whole-system vulnerabilities, such as new technical specifications for all nuclear units based on an event at a specific plant.

[35] Heraclitus, Greek philosopher, circa 500 B.C.

[36] See the Appendix for case studies of historical events.

Figure 5. Historical Events World Map



No generation resource is free from risks that can negatively impact the electric power sector. These risks are global, and can affect any geography or political construct. Additional risks of increasing concern include man-made, purposely malicious attacks[37] designed to inflict maximum disruption to electric grid operations. The reaction to, and impacts from, events that reduce reliability and fuel security can be widespread and long-lasting.[38] Although most of these events are unpredictable, PJM must be prepared. Measures beyond traditional capacity procurement or economic dispatch may be needed to reduce risks associated disruptive events and maintain system reliability and resilience.

Reliability

PJM's analysis of reliability, as related to fuel diversity and security, builds upon the work initiated by the North American Electric Reliability Corporation (NERC) and the power industry to define essential reliability services, which comprise a subset of generator reliability attributes.

An awareness of the existing level of generator reliability attributes is required to understand how retirements of conventional generation (e.g., coal and nuclear) and replacement of capacity with natural gas generators and variable energy resources will impact reliable operation of the bulk electric system. At the same time, resources on the distribution system are increasing because of demand response programs and growth of distributed energy resources.

[37] Examples of man-made attacks include, but are not limited to, High Altitude Electromagnetic Pulse, coordinated cyber or physical attacks, etc.

[38] See the Appendix for examples of historic events and impacts.

Although each fuel source produces real power - megawatt-hours (MWh) that are ultimately consumed by customers - each also contributes to overall grid reliability by providing generator reliability attributes.

PJM has undertaken various initiatives to analyze, develop, or modify system requirements that, directly or by extension, maintain acceptable levels of generator reliability attributes. The initiatives include Capacity Performance, enhanced standards for inverter-based resources, centralized forecasts (wind, solar and distributed energy resources), business rules which support dispatchability of variable energy resources, "Pay for Performance" regulation service, 15-minute interchange intervals, and the PJM Renewable Integration Study.[39]

Defining Generator Reliability Attributes

To better quantify the generator reliability attributes that contribute to grid reliability, PJM compiled information from various NERC initiatives that defined Interconnected Operations Services[40] and Essential Reliability Services,[41] as well as information from renewable integration studies, the PJM ancillary service markets,[42] the PJM Capacity Performance Initiative,[43] the PJM Advanced Technology Pilot program[44] and feedback from PJM staff, PJM members, and other industry experts. The resulting generator reliability attributes are defined and described below.

Figure 6 shows a matrix of the generator reliability attributes[45] based on 2016 capabilities and PJM operational experience for different resource types to include Coal, Natural Gas Steam, Natural Gas CT, Oil Steam, Oil CT, Nuclear, Solar, Wind, Hydro, Battery/Storage and Demand Response.

The capability to provide various generator reliability attributes may change in the future as a result of changes in technology or resource mix driven by regulation. The matrix is intended primarily to group units by fuel type, and as such, may not exclusively represent every combination of fuel, prime mover and technology type. Should the actual, future fuel mix evolve such that the potential exists for the quantity of generator reliability attributes to fall below that which is necessary to maintain reliable grid operations, then operations, market incentives and regulatory structures may need to shift to provide incentives to ensure adequate levels of these attributes are maintained.

[39] http://www.pjm.com/~/media/committees-groups/subcommittees/irs/postings/pjm-pris-final-project-review.ashx

[40] http://www.nerc.com/docs/pc/IOSrefdoc.pdf

[41] http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf

[42] PJM Balancing Manual (M12) http://www.pjm.com/~/media/documents/manuals/m12.ashx

[43] http://www.pjm.com/~/media/committees-groups/committees/mic/20160119-special/20160119-capacity-performance-parameter-limitations-informational-posting.ashx

[44] http://pjm.com/markets-and-operations/advanced-tech-pilots.aspx

[45] See the Generator Reliability Attribute section in the Appendix for further explanation.

Figure 6. Generator Reliability Attribute Matrix

● = Exhibits Attribute
◓ = Partially Exhibits Attribute
○ = Does Not Exhibit Attribute

Resource Type	Essential Reliability Services (Frequency, Voltage, Ramp Capability)					Fuel Assurance		Flexibility			Other		
	Frequency Response (Inertia & Primary)	Voltage Control	Ramp										
			Regulation	Contingency Reserve	Load Following	Not Fuel Limited (> 72 hours at Eco. Max Output)	On-site Fuel Inventory	Cycle	Short Min. Run Time (< 2 hrs.)/ Multiple Starts Per Day	Startup/ Notification Time < 30 Minutes	Black Start Capable	No Environmental Restrictions (That Would Limit Run Hours)	Equivalent Availability Factor
Hydro	●	●	●	●	●	○	◓	●	●	●	●	◓	●
Natural Gas - Combustion Turbine	●	●	◓	●	◓	●	○	●	●	●	●	◓	◓
Oil -Steam	●	●	●	●	●	●	●	●	○	○	○	○	◓
Coal - Steam	●	●	●	●	●	●	●	◓	○	○	○	◓	◓
Natural Gas - Steam	●	●	●	●	●	●	○	●	○	○	●	◓	◓
Oil/ Diesel - Combustion Turbine	●	●	○	●	○	○	●	●	●	●	●	○	◓
Nuclear	◓	●	○	○	◓	●	●	○	○	○	○	◓	●
Battery/ Storage	◓	◓	●	●	○	○	○	●	●	●	◓	●	●
Demand Response	○	○	◓	◓	◓	◓	◓	●	●	◓	○	●	●
Solar	◓	◓	○	○	◓	○	○	●	●	●	○	●	●
Wind	◓	◓	○	○	◓	○	○	●	●	●	○	◓	●

Generator Reliability Attributes Description

Key generator reliability attributes defined and analyzed as part of this paper include frequency response, voltage control, ramp, fuel assurance, flexibility, black start, environmental restrictions and equivalent availability factor.

Frequency Response

The frequency of alternating current on an interconnected transmission system (typically 60 Hz in the U.S.) is a key indicator of the system's health and stability. Frequency response is an essential reliability service as defined by NERC, and is provided through the interaction of three components – synchronous inertia,[46] primary frequency response[47] and secondary frequency response.[48] Frequency will be impacted by any imbalance between load and generation, deviating upward when generation exceeds demand, and deviating lower when generation is insufficient to meet demand. Frequency response components work together to arrest frequency changes caused by an imbalance between generation and demand, and to return the system to scheduled frequency.

The initial rate at which system frequency changes depends on the amount of inertial response available at the time of the event. Historically, the majority of inertial response has been supplied by large synchronous generators[49] such as coal-fired steam units. Once the frequency change has been arrested, primary and secondary frequency response resources can provide additional power to eventually return the system to normal frequency through ancillary services like area regulation and Security Constrained Economic Dispatch (SCED).

Nuclear plants may be prohibited from providing primary frequency response based on their licenses. Controls on (legacy) non-synchronous solar and wind generation are not capable of providing frequency response. However, newer non-synchronous generators,[50] such as wind and solar, have the ability to provide frequency response with smart inverters, which can be programmed to provide frequency response for very short periods using power electronics. Future resource capabilities likely will change based on the outcome of the Federal Energy Regulatory Commission (FERC) Notice of Proposed Rule Making entitled Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response.[51] In the NOPR, the FERC proposes requiring all new interconnected resources to provide frequency response. PJM's analysis assumes that, in future mixes, these resources will be capable of providing primary frequency response. Market changes may be needed, however, to incent non-synchronous generators to provide primary frequency response because, to do so, they need to operate below their maximum output.

[46] Synchronous Inertia - Due to electro-mechanical coupling, a generator's rotating mass provides kinetic energy to the grid (or absorbs it from the grid) in case of a frequency deviation Δf arresting frequency decline and stabilizing the electric system. The contribution of inertia is an inherent and crucial feature of rotating synchronous generators.

[47] Primary Frequency Response - involves the autonomous, automatic, and rapid action of a generator, or other resource, to change its output (within seconds) to rapidly dampen large changes in frequency.

[48] Secondary Frequency Response, also known as automatic generation control, is produced from either manual or automated dispatch from a centralized control system. It is intended to balance generation, interchange and demand by managing the response of available resources within minutes as opposed to primary frequency response, which manages response within seconds. Secondary frequency response is accounted for in the Ramping generator reliability attribute.

[49] Synchronous generator is an alternating-current generator whose average speed of normal operation is exactly proportional to the frequency of the system to which it is connected.

[50] Non-Synchronous generator is an alternating-current generator whose average speed of normal operation is independent of the frequency of the system to which it is connected.

[51] (Docket No. RM16-6-000), issued November 17, 2016, http://ferc.gov/whats-new/comm-meet/2016/021816/E-2.pdf

Voltage Control

The second key indicator of the health and stability of the interconnection is system voltage. Voltage control, also an essential reliability service, is the ability of a generator to either inject or absorb "reactive power" either prior to or after a system disturbance (such as a generator or transmission facility tripping out of service) in order to maintain or restore system voltages to prescribed levels. Unlike real power (megawatts), reactive power (mega Volt Ampere reactive or MVAR) cannot be transmitted over long distances. For this reason, reactive power reserves must be geographically dispersed, located in close proximity to customer load. If sufficient reactive reserves are not maintained locally, disturbances can result in instability and potentially localized or wide-area blackouts. Typically, synchronous generator's voltage control is dependent upon reactive power control and physical moving parts of a generating machine.[52] New nonsynchronous generators are equipped with smart inverters to provide dynamic reactive power and voltage control capabilities as mandated by FERC Order 827.[53]

Ramping

Ramping is the ability of a generator to increase or decrease real power (megawatts) in response to changes in system load, interchange schedules or generator output, in order to maintain grid reliability and compliance with applicable NERC standards. The generator reliability attribute of ramping is further defined by several attributes:

- **Regulation:** An amount of energy reserves from a resource that is responsive to automatic generation control, and is sufficient to provide normal regulating margin and frequency control as required in PJM Manual 12: Balancing Operations.[54]
- **Contingency reserve (synchronized reserves/non-synchronized reserves)**: The provision of capacity that may be deployed to respond to a contingency that results from a large mismatch between generation and demand, typically resulting from a loss of a generator.
- **Load following (dispatchable):** A generator that adjusts its power output as demand for electricity fluctuates throughout the day.

Load following capability varies by technology and/or fuel type. Modern utility-scale wind and solar plants typically can control their output from the full (currently available) power level down to zero. Conventional generators typically have minimum load levels below which they cannot reduce power. Minimum loads may be 40 percent or higher for coal plants, and nuclear plants typically offer limited load following capability. Because some combustion turbines must be block-loaded for emissions reasons, they offer no load following capability. Ramping control is typically faster and more accurate for the new natural gas combined cycle, wind and solar plants than for legacy fossil-fired or nuclear plants, although the capability for intermittent resources such as wind and solar plants to provide ramping capability is significantly limited by the uncertain availability of their fuel source. Such resources could therefore be extremely capable of providing ramping capability in the downward direction, but the upward direction is potentially constrained.

Traditionally, nuclear units in the PJM footprint have not been dispatchable or configured for load following. Reductions to nuclear units are done in a methodic and planned fashion, and the units typically take several hours to ramp down and to

[52] http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF_Draft_Concept_Paper_Sep_2014_Final.pdf

[53] https://www.ferc.gov/whats-new/comm-meet/2016/061616/E-1.pdf

[54] http://www.pjm.com/~/media/documents/manuals/m12.ashx

ramp back up. During emergency conditions, nuclear units would ramp down faster, but ramping up still would occur in a slower, more controlled fashion over several hours.

As a result of negative Locational Marginal Prices (LMP) market signals, some nuclear units have begun to operate in a load following manner much like a large steam unit. These nuclear resources have been able to operate as dispatchable resources in a range between 85 percent and 100 percent of their economic maximum.

As penetration of variable energy resources increases, additional load following capability is required from other resources in order to reliably offset rapid changes in output from renewable resources.

An August 2016 study conducted by the U.S. Department of Energy's National Renewable Energy Laboratory concluded that a portfolio mix consisting of greater than 30 percent renewable energy resources such as wind and solar "will cause other generators to ramp and start more quickly."[55]

Fuel Assurance

For PJM operations, fuel assurance is defined as the ability of a resource to maintain economic maximum energy output for 72 hours, based on the definition of fuel limited resources within the PJM Manual 13: Emergency Operations Attachment C.[56] Fuel assurance considers the capability of the resource to store fuel on-site in order to limit the exposure to a single common event. It is necessary in order to provide the energy and reserves needed to maintain system reliability, independent of external delivery infrastructure or rapidly changing weather patterns.

Flexibility

Flexibility is the ability of a resource to cycle, its total time required to start (including notification time), minimum run time and the number of starts per day.

- Cycle is the ability of a unit to start up and shutdown more than once in every 24-hour period.
- Startup/Notification Time: the sum total duration of notification and startup time of less than or equal to 30 minutes.
- Minimum Run Time/multiple starts per day: minimum run times less than or equal to two hours per start.

Flexible generators can come on or off-line and run for short periods of time when system load, interchange, or generator output is rapidly changing, which is most common during early morning periods or late afternoon periods.

Flexibility also is needed to maintain system reliability during minimum load periods, peak load periods, periods of rapidly changing variable energy resources, during transmission or capacity emergency conditions, or due to real-time changes in load profile and/or unit availability after day-ahead resource commitments are communicated.

The level of generator flexibility varies by technology and/or fuel type. Combustion turbines, hydro units and diesel generators typically provide the most flexibility, while fossil steam and nuclear units provide the least flexibility.

[55] http://www.nrel.gov/docs/fy16osti/64472-ES.pdf

[56] http://www.pjm.com/~/media/documents/manuals/m13.ashx

Both wind and solar resources have the flexibility to be dispatched in the downward direction in response to system constraints or minimum generation situations. Due to the variability of the sun and wind, however, their return to previous output cannot be assured, limiting the flexibility of these resources.

Other

The "other" category of generator reliability attributes captures other relevant and noteworthy attributes. It includes:

- **Black start capability:** A unit that can start independent of a grid electrical source and that can supply electricity to the grid for the purposes of restoring the electric power grid and other generation resources following a widespread loss of the electric power grid. Typically, combustion turbines, hydro, diesel generators, as well as batteries, can be black start capable.
- **Environmental restrictions:** Typically a regulatory restriction, environmental restrictions may limit the number of hours a unit can produce power. Resources such as solar, batteries/storage and demand response have very few, if any, applicable environmental restrictions. Coal, natural gas, and nuclear steam units, as well as wind and hydro units, to some degree, have some environmental restrictions, which, as a rule, have limited impact on system operations. Coal and natural gas resources generally have limits on air emissions that can affect operations; nuclear units at times have encounter limits on cooling water, including pond/river levels and temperatures. Wind turbines shut down automatically during periods of high winds and sometimes are affected by bird or bat migration patterns. Hydro units have pond level and minimum flow requirements. Generation assets that burn liquid fuels tend to have the most restrictions, particularly tied to their air permits.

  Equivalent availability factor: The equivalent availability factor recognizes the equivalent demand forced outage rate, which is a measure of the probability that generating unit will not be available due to a forced outage or forced deratings, when there is a demand on the unit to generate.[57] For solar and storage, the equivalent availability factor is also calculated as a capacity factor, using outage data from eDART which is an electronic, internet-based tool used by PJM and member company operations for outage tracking[58] in lieu of generator availability data (GADs), since NERC GADs reporting requirements only apply to conventional resources larger than 20 MW.[59] For wind, the equivalent availability factor is calculated as a ratio of reductions/outages plus outages to generated megawatts in order to more accurately take into account wind conditions. For demand response resources, equivalent availability factor was determined by actual performance during prior load management events.

  For purposes of comparison in the matrix presented in Figure 6 above, generator equivalent availability factors are grouped as follows: >90 percent (exhibits attribute), 80-90 percent (partially exhibits attribute), and <80 percent (does not exhibit attribute).

Contributions from Other Resources

Although this paper is primarily focused on fuel security for grid-connected generating resources, other resources such as Demand Response and Distributed Energy Resources also have to be accounted for. The characteristics of each of these are described in more detail below.

57 https://www.pjm.com/~/media/documents/manuals/m18.ashx

58 http://www.pjm.com/markets-and-operations/etools/edart.aspx

59 http://www.nerc.com/pa/rapa/gads/pages/default.aspx

Demand Response

Demand response is an end-use customer who changes electric usage from normal levels in response to high real-time electricity prices or when system reliability is jeopardized.

PJM has approximately 8,500 MW of demand response committed for the 2016/2017 delivery year. The capacity commitment is primarily for limited demand response (6,800 MW), which has obligation to respond only June through September for up to six hours per event for 10 events per delivery year. The remainder is composed of extended summer demand response, annual demand response and annual Capacity Performance demand response.

Demand response is transitioning from seasonal products to annual Capacity Performance products. Demand response can participate voluntarily in the energy and ancillary service markets. Table 1 summarizes demand response participation in PJM energy and ancillary services markets.

Table 1. Demand Response Participation in PJM Markets

	Energy (MW)	Sync Reserve (MW)	Regulation (MW)
Maximum	2500	400	36
Summer Peak	1000	180	36
Typical	100	60	<15

For demand response, the attributes identified in Figure 6 above are based how demand response participates within the PJM market based on current PJM business rules and market conditions (prices).

Distributed Energy Resources

According to the NERC DER Task Force Report from November of 2016: "A distributed energy resource (DER) is any resource on the distribution system that produces electricity or actively alters the balance of demand or generation, and that is not otherwise included in the formal NERC definition of the bulk energy system."[60]

A grid operator's visibility of behind-the-meter real-time DER behavior is limited because today behind-the-meter DER is not required to supply telemetry data (such as output) to the grid operator. While telemetry for some utility-scale DER units may be available, the process for obtaining the data varies based on the local electric distribution company. Many DERs are solar photovoltaic generators that produce power only during specific times of day. Output from these solar units is not coincident with system peak loads during certain times of year. Depending on the level of penetration, DERs could require increased de-commitment/re-dispatch of centrally dispatched resources or off-system schedules to meet the balancing obligations. Recently proposed improvements to integration requirements for DER and implementation of a solar forecast within PJM are intended to lessen the impact on existing resources and improve market efficiency.

Most existing DERs were not designed to provide active voltage control and frequency response. Technology exists to allow DERs to provide these essential reliability services.[61] However, there is currently limited coordination between DER installations and bulk power system requirements enumerated in NERC standards.[62] This is because, in most cases,

[60] NERC DER Task Force Report - http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/May%202016%20Meeting%20Materials.pdf

[61] As specified in IEEE 1547 http://grouper.ieee.org/groups/scc21/1547_revision/1547revision_index.html

[62] Such as PRC-024-2 at http://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-024-2.pdf

DERs do not meet NERC registration criteria under the current NERC functional model,[63] which does not require most DERs to register as a Generator Owner or Generator Operator. As such, NERC standards would not apply to these entities.

Generator Reliability Attribute Quantification

The reliability attribute matrix (Figure 6 above) summarizes the capabilities of each resource type to provide services that are essential to system reliability. Using detailed analysis of generator operational data, each reliability attribute was quantified[64] to assess the capability of each resource type to provide each reliability service, and determine the total amount of each attribute available in different resource portfolios.

Importantly, the quantification approach was not based on energy dispatch models and does not capture the amount of each generator reliability attribute provided by resources that are online at any moment in time. The analysis does not capture the system requirement for each generator reliability attribute because the needs of the electric system are dynamic and dependent on the economic dispatch of resources. Instead, the quantification of the generator reliability attributes was based on the attribute capability of each resource type and the resource share of unforced capacity[65] in each portfolio. The total quantity of each attribute in a resource portfolio is the maximum amount available.

There were three main steps in quantifying the generator reliability attributes:

- Evaluate the capability of each resource type to provide generator reliability attributes, as outlined by PJM in Figure 6, and determine the total amount of each attribute in the system today.
- Develop resource type-specific capability factors for each generator reliability attribute that can be applied to the unforced capacity (UCAP) of each resource type in a resource portfolio. These factors were calculated based the attribute capabilities in the system today with the purpose of relating quantities of attributes to different UCAP amounts of each resource type.
- Apply the attribute capability factors to estimate amounts of each attribute and percent of total attribute capability provided by each resource type in potential future portfolios.

Current PJM operational data and experience were used quantify each reliability attribute in the system today. This served as the basis for the resource type-specific capability factors used to estimate the attribute capabilities of different portfolios. Additional detail about how each of the reliability attributes was quantified and converted into factors is detailed in the Appendix.

[63] http://www.nerc.com/pa/comp/Pages/Registration-and-Certification.aspx

[64] The quantification methodology is explained in more detailed in the Appendix.

[65] There are numerous ways the industry quantifies generation and capacity. Below are a few examples to help explain these terms and provide comparison:

Generation or energy – MWh, same for all resources

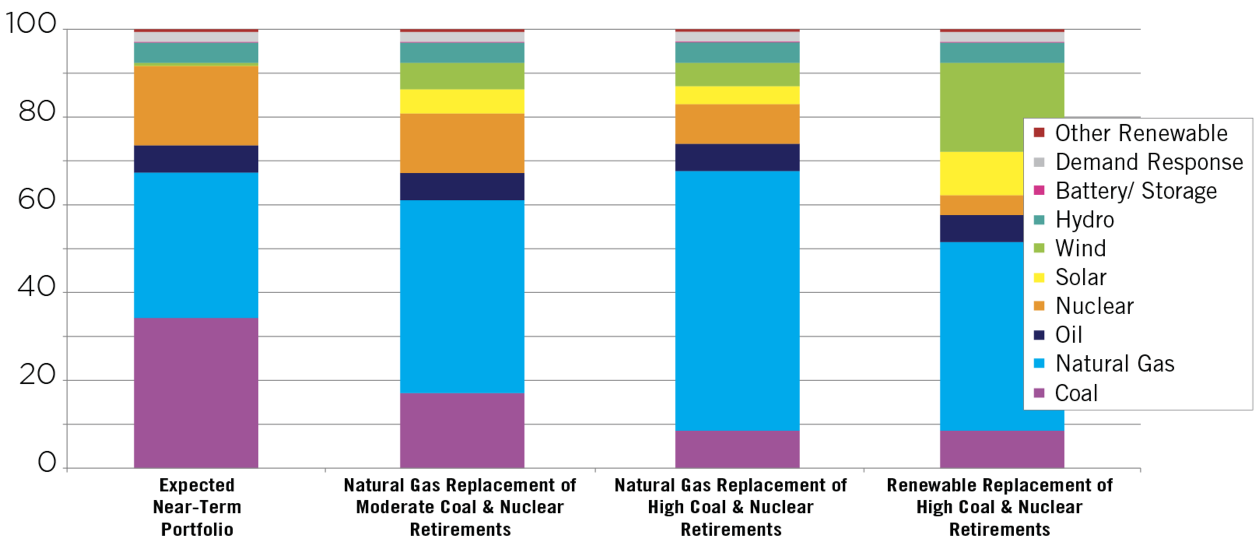
- Nameplate rating – MW, maximum sustained capability
- Unforced capacity (UCAP) – MW, value of a capacity resource in the PJM Capacity Market. For generating units, the unforced capacity value is equal to installed capacity multiplied by (1- unit's EFORd). For demand resources and energy efficiency resources, the unforced capacity value is equal to demand reduction multiplied by Forecast Pool Requirement.
- Example: Wind – 100MW ICAP = 13MW UCAP = 0.3 TWh per year (assuming 30 per cent net capacity factor)
    - Generator portfolio with 20 per cent of UCAP from wind compared with current portfolio:
    - 20 percent: 33,413 MW UCAP = 257,025 MW nameplate = 675.5 TWh energy per year (assuming 30 percent net capacity factor)
    - Current: 1085 MW UCAP = 8346 MW nameplate =21.9 TWh energy per year (assuming 30 per cent net capacity factor)

As the fuel mix was adjusted based on possible future scenarios, the analysis shows how much of each reliability attribute was lost or gained. These results show the impact on reliability for each possible future fuel mix scenario. Resource portfolios with reduced amounts of reliability attributes will have less capability to rely on during real-time operations to meet system needs, and may be at increased reliability risk. Such scenarios would require PJM and stakeholders to consider new technology requirements or market mechanisms to incent enhanced capability for the reliability services of concern.

Figure 7 compares the resource share of unforced capacity in PJM's expected near-term portfolio[66] and three sample future portfolios.[67] Figure 8 compares the total quantity of each reliability attribute in each portfolio, with the expected near-term portfolio as a baseline. The axis in Figure 8 is the generator reliability attribute ratio, which indexes the total amounts of attribute capability in the sample portfolios relative to that of the expected near-term portfolio. Values less than 1.0 indicate that there is less total attribute capability relative to the baseline. Values greater than 1.0 indicate there is greater total attribute capability relative to the baseline.

Figure 7 and Figure 8 depict the first major takeaway from quantifying the reliability attributes. As the resource mix moved in the direction of less coal and nuclear generation, there was a decrease in Fuel Assurance attribute capability and an increase in Flexibility attribute capability. These shifts were driven by differing capabilities of the resource types that comprise each portfolio. Natural gas, wind, and solar do not exhibit the same level of fuel assurance capability as do coal and nuclear. They do exhibit higher levels of the flexibility capability, however.

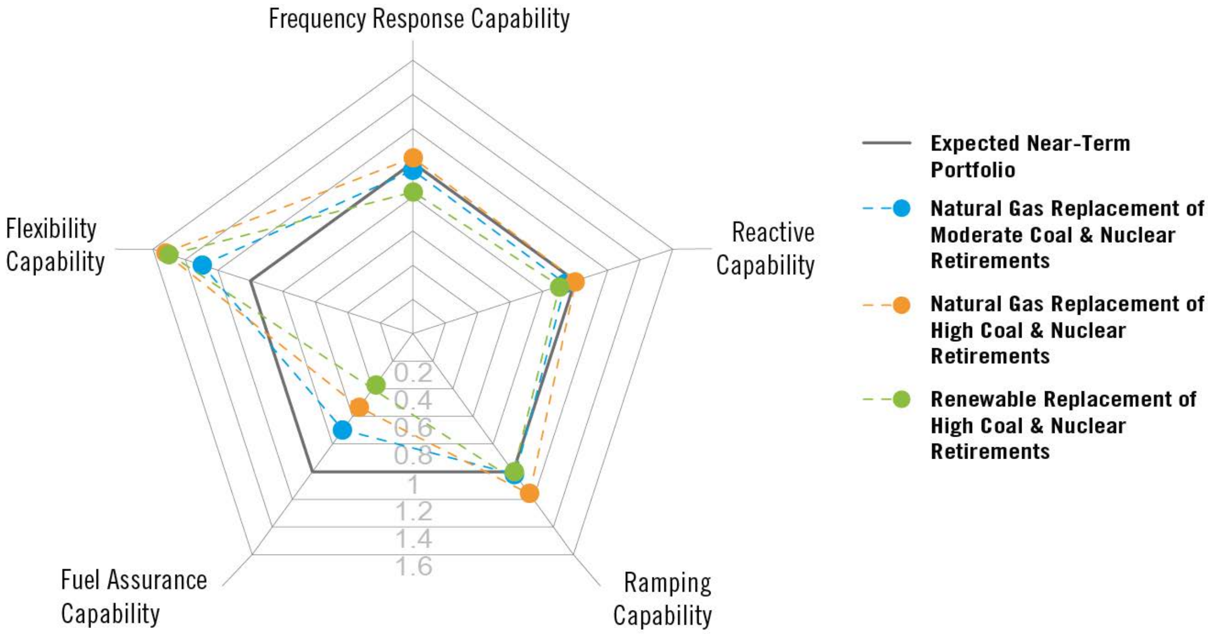
Figure 7. Illustrative Resource Portfolios - Percent of Total Unforced Capacity



[66] The 'Expected Near-Term PJM Portfolio' was established by projecting the composition of PJM's generation fleet out to 2021, and is described in more detail in the Risk Analysis Section.

[67] These are sample portfolios from the 360 potential future portfolios, which are described in the Risk Analysis section and the Appendix.

Figure 8. Shift of Generator Reliability Attributes in Changing Portfolios[68]



The heat maps in Table 2 compare the percent of total attribute capability provided by each resource type in the baseline portfolio and sample future portfolios. Table 2 illustrates the second major conclusion from quantifying the reliability attributes: as the amount of coal and nuclear resources in future portfolios decreases, the percent of total attribute capability provided by natural gas resources increases, indicating an increased reliance on natural gas resources to provide reliability attributes. The shift in reliance was most evident in the sample portfolio labeled "Natural Gas Replacement of High Coal & Nuclear Retirements." Compared to the baseline, natural gas resources contribute 69 percent of total Reactive Capability, a large shift from 39 percent.

Additionally, the highlighted boxes around specific attribute categories in Table 2 further illustrates that there was a reduced amount of total attribute capability relative to the baseline portfolio. For example, the sample portfolio labeled "Renewable Replacement of High Coal & Natural Gas Retirements" had less total capability for frequency response, reactive, ramp, and fuel assurance attributes relative to the baseline portfolio, and increased reliance on natural gas to provide these attributes.

[68] The axis values in Figure 8 are reliability attribute ratios, which index the total amounts of capability for each attribute in the sample portfolios relative to the total amount in the baseline portfolio. The attribute ratios for the baseline portfolio =1.0. Values less than 1.0 indicate that there is less total attribute capability relative to the baseline. Values greater than 1.0 indicate there is greater total attribute capability relative to the baseline.

Table 2. Shift in Reliance on Resource Types to Provide Generator Reliability Attributes

	Unforced Capacity	Frequency Response Capability	Reactive Capability	Ramp Capability	Fuel Assurance Capability	Flexibility Capability	Unforced Capacity	Frequency Response Capability	Reactive Capability	Ramp Capability	Fuel Assurance Capability	Flexibility Capability
	Expected Near-Term Portfolio						**Natural Gas Replacement of Moderate Coal & Nuclear Retirements**					
Coal	34.2%	19.7%	35.5%	27.9%	32.9%	5.8%	17.1%	12.8%	18.9%	15.3%	25.1%	2.2%
Natural Gas	33.1%	31.2%	39.0%	47.9%	7.6%	50.4%	44.0%	38.1%	55.0%	61.2%	13.5%	51.5%
Oil	6.2%	15.5%	6.8%	5.6%	21.4%	15.9%	6.2%	14.7%	7.3%	5.5%	22.5%	12.3%
Nuclear	18.1%	9.7%	13.3%	0.0%	22.7%	0.0%	13.6%	7.7%	10.6%	0.0%	22.9%	0.0%
Solar	0.1%	1.5%	0.0%	0.0%	0.0%	0.1%	5.5%	2.8%	0.6%	0.0%	0.0%	3.9%
Wind	0.6%	3.0%	0.2%	0.1%	0.0%	1.3%	6.1%	5.6%	2.2%	0.6%	0.0%	9.4%
	Renewable Replacement of High Coal & Nuclear Retirements						**Natural Gas Replacement of High Coal & Nuclear Retirements**					
Coal	8.6%	10.0%	10.7%	7.6%	21.4%	0.9%	8.6%	9.0%	8.8%	6.4%	18.6%	1.0%
Natural Gas	43.0%	43.5%	61.1%	65.3%	20.3%	40.9%	59.2%	45.2%	69.3%	72.8%	21.6%	58.7%
Oil	6.2%	15.5%	8.3%	6.1%	24.8%	10.0%	6.2%	14.5%	6.8%	4.9%	23.3%	10.4%
Nuclear	4.5%	3.2%	4.1%	0.0%	16.1%	0.0%	9.0%	4.8%	6.7%	0.0%	20.0%	0.0%
Solar	9.9%	2.8%	1.2%	0.1%	0.0%	5.7%	0.1%	2.8%	0.0%	0.0%	0.0%	0.0%
Wind	20.3%	5.6%	8.4%	2.3%	0.0%	25.5%	9.3%	5.6%	3.2%	0.9%	0.0%	12.4%

NOTE: Hydro, battery/storage, demand response and other renewables are excluded from this graphic because their contribution to the total amount of reliability services is consistent in each example portfolio.

Evaluating the total amount of generator reliability attributes in different resource portfolios aids in understanding the potential impact of generation mix change. The quantified generator reliability attributes were used to create a composite reliability index that was applied in a reliability risk model for 360 potential future generation portfolios and is discussed in the next section.

Risk Analysis

This analysis examined the reliability risk of various potential resource portfolios.[69] Two components of reliability risk were studied: 1) resource adequacy reliability and 2) operational reliability, defined as the capability to provide the generator reliability attributes identified in Figure 6 and quantified in the previous section. Resource adequacy addresses the amount of capacity needed to satisfy a forecasted peak load while meeting the Loss of Load Expectation criterion, whereas the generator reliability attributes supply the grid's day-to-day operational needs. These generator reliability attributes are generally not included in PJM's resource adequacy studies. Note that there can be multiple portfolios that meet PJM's resource adequacy criterion but that may not have adequate ability to provide operational reliability.

To examine future portfolio compositions, recent trends in PJM's generator interconnection queue and deactivation announcements were used to develop 360 potential portfolios. Each prospective portfolio was evaluated for its ability to provide adequate levels of the generator reliability attributes and was benchmarked against PJM's projected 2021 capacity mix.[70] Portfolios that are best able to provide the generator reliability attributes under four operational states were identified.

Method

PJM developed a methodology to determine the relative operational reliability and assess the risk of each prospective portfolio. Figure 9 shows the steps associated with the Risk Analysis Methodology.

Figure 9. Risk Analysis Methodology

In the first step, a baseline portfolio is established by projecting the composition of PJM's current resource mix out to 2021.[71] The baseline portfolio is developed to meet the industry standard resource adequacy "one day in 10 year" criterion, known as the Loss of Load Expectation (LOLE)[72]. To ensure that the portfolio has adequate capacity to meet the LOLE,

[69] PJM performed the risk analysis based on unforced capacity provided by resources within a portfolio. Energy was not considered in this section.

[70] Greater detail on how portfolio capabilities are calculated is located in the Appendix.

[71] The baseline portfolio was projected out to 2021 to account for near-term trends in announced retirements and added capacity from the PJM Generation Queue. More detail on this approach is in the Appendix.

[72] ReliabilityFirst Standard BAL-502-RFC-02 – http://www.nerc.com/files/BAL-502-RFC-02.pdf

the total megawatt amount of unforced capacity within the portfolio was set equal to a fixed megawatt reliability requirement and the installed reserve margin[73] is allowed to vary.

Next, a set of alternative portfolios was created by incrementally retiring coal and nuclear units and replacing them with natural gas, solar and wind resources. All other resource types were held constant at the baseline level. Each alternative portfolio was derived such that it meets the "one day in 10 year" LOLE criterion. Since today's capabilities in storage are limited, and cannot account for large changes in wind and solar generation, the portfolios were subjected to a second LOLE test to account for intermittency in output from wind and solar. This second test ensured that portfolios with large unforced capacity shares of intermittent resource were able to serve load during hours that the output of these resources was significantly lower than their capacity credits. Portfolios that failed this second LOLE test were considered infeasible.

After imposing the second LOLE test, the feasible portfolios were assessed for their ability to provide the generator reliability attributes displayed in Figure 6 under four operational states: normal peak conditions, light load, extremely hot weather and extremely cold weather. Reliability indices that quantify the performance[74] of each portfolio against the baseline portfolio's performance were created under each operational state. These reliability indices were averaged to create a composite reliability index.[75]

The composite reliability index (CRI) measured a portfolio's capability to supply all of the generator reliability attributes across the four operational states, relative to the baseline portfolio. Low composite reliability indices indicated reduced capability of a portfolio to provide the generator reliability attributes. As portfolios became less capable to provide the generator reliability attributes that meet system needs during real-time operations, operational reliability risk increased. Therefore, to identify trends in portfolio compositions that potentially pose operational reliability risk that may necessitate additional technology requirements or market mechanisms, the portfolios were placed into performance categories based on composite reliability index values.

Table 3 describes the reliability criteria used to classify each performance category.

Table 3. Performance Classification

Performance	Classification Criterion	Technology Requirements or Market Mechanisms Necessary to Ensure Adequate Reliability Services
Infeasible	Violates LOLE	Highly likely
At-Risk-for-Underperformance	CRI < 0.90	Highly likely
Less-than-Baseline	0.90 < CRI < 1	Likely
Greater-than-Baseline	CRI > 1	Unlikely
Desirable	RI > 0.95 in all operational states	Highly unlikely

73 The Installed Reserve Margin is the installed capacity percent above the forecasted peak load required to satisfy the LOLE. PJM typically has resources in the form of capacity or energy-only that exceeds the IRM requirement and were not considered as part of the Risk Analysis Methodology.

74 Greater detail on how portfolio performance is quantified is described in the Appendix.

75 Each resource's capability to provide the generator reliability attributes is calculated using the quantification method explained in the reliability attribute quantification section.

Finally, to test the hypothesis that greater fuel diversity results in greater reliability, the Shannon-Wiener diversity index was compared to the composite reliability indices of the portfolios. The Shannon-Wiener diversity index is a commonly used measure of diversity that PJM adapted to measure two of the three components of fuel diversity described in the background section: 1) the variety of fuel types in a portfolio and 2) how balanced the share of unforced capacity is among the fuel types.[76] The third component of fuel diversity, disparity, was captured by the composite reliability index.

In summary, this analysis provides information regarding the capability of potential portfolios to provide operational reliability across a range of operational states and also regarding the relationship between fuel diversity and reliability.

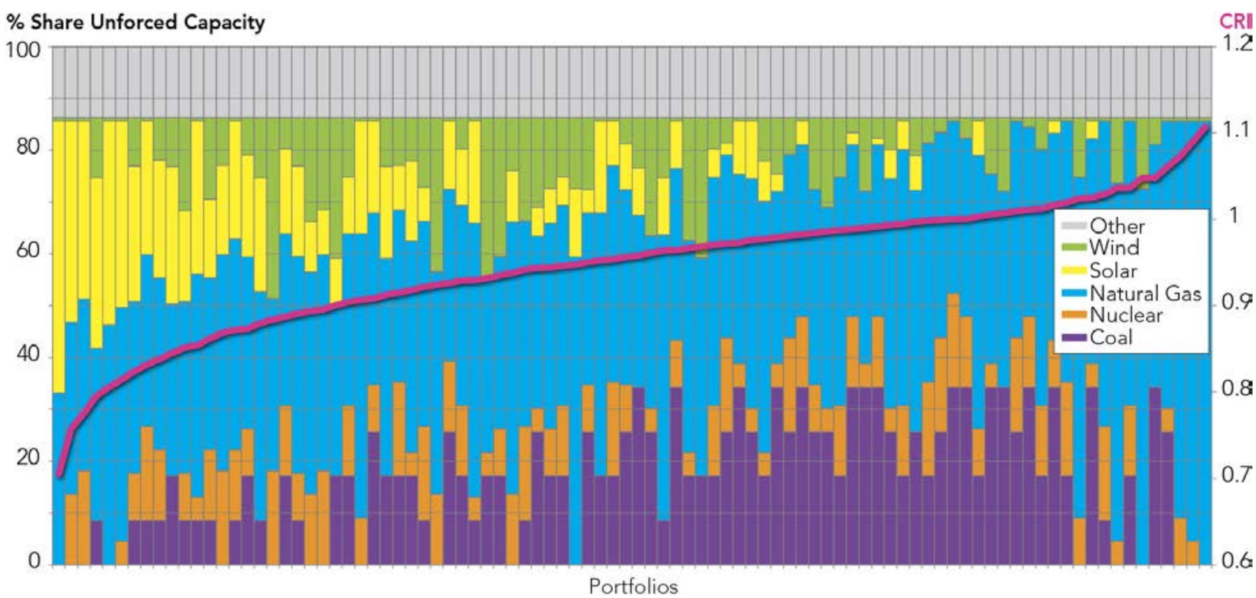
Results

Composite Reliability Index

Composite reliability indices of the portfolios considered in this analysis ranged from 0.70 to 1.11 with the baseline portfolio's CRI equal to 1.00. This range indicated that the lowest performing portfolio's ability to provide the full range of generator reliability attributes was approximately 30 percent less than that of the baseline portfolio. Likewise, the highest performing portfolio's measured capability was nearly 11 percent greater than the baseline.

Figure 10 displays the overall trend between the composite reliability index and various resource portfolios. The composition of the portfolios was tracked on the primary vertical and is represented by the stacked bar graph. The corresponding composite reliability index for each portfolio was tracked on the secondary vertical and is represented by the red line.

Figure 10. Portfolio Composition and Composite Reliability Index



The composite reliability indices varied across portfolios and were dependent upon the composition of the portfolio. Despite variation, broad trends emerged by resource type:

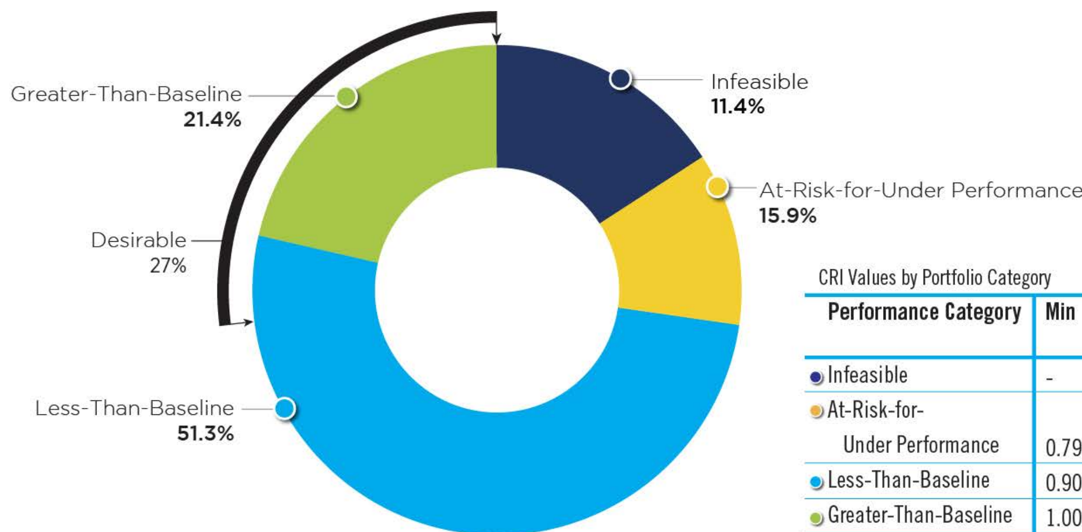
[76] The Shannon Wiener Index only captures the variety and balance aspects of diversity, discussed in the Background section. The disparity aspect of diversity is accounted for in the differing generator reliability attribute capabilities of each resource type.

- Portfolios with the largest unforced capacity shares of wind and solar tended to have the lowest composite reliability indices. This indicates that these portfolios have reduced capability in the some of the generator reliability attribute categories, specifically the Essential Reliability Services and Fuel Assurance, relative to the baseline portfolio.
- Composite reliability indices generally improved as unforced capacity shares of nuclear, coal and natural gas increased. This is due to these fuel types collectively exhibited the majority of the generator reliability attributes displayed in Figure 6.
- When coal and nuclear units were retired and replaced, portfolios with the highest composite reliability indices tended to be ones in which natural gas is the predominant replacement resource. This is because natural gas provides a broad range of the generator reliability attributes.

Composition of the Performance Categories

To identify trends in portfolio compositions that potentially pose operational reliability risk that may necessitate additional technology requirements or new market mechanisms, the portfolios were placed into performance categories based on composite reliability index values. Figure 11 describes the distribution of the composite reliability indices.

Figure 11. Distribution of the Performance Categories



CRI Values by Portfolio Category

Performance Category	Min	Max	LOLE Criterion
Infeasible	-	-	Failed
At-Risk-for-Under Performance	0.79	0.90	Met
Less-Than-Baseline	0.90	0.99	Met
Greater-Than-Baseline	1.00	1.11	Met
Desirable	0.95	1.11	Met

Infeasible

The determination of a portfolio's feasibility in this analysis was independent of its composite reliability index values. Only portfolios that failed to meet the second LOLE test were categorized as infeasible. Most portfolios with an unforced capacity share of solar above 20 percent violated LOLE and were therefore categorized as infeasible. This outcome is the result of an inability for these portfolios to serve load during hours in which solar resources' output is significantly below its 38 percent capacity credit (for example, during high-load winter days at hours with no sunlight or high levels of cloud cover). It is important to note that not all portfolios with an unforced capacity share of solar greater than 20 percent violated the second LOLE test. Some portfolios with unforced capacity shares of solar greater than 20 percent benefited from the over-performance of wind at times when the solar resources' output was significantly below its 38 percent capacity credit.[77] As a result, these portfolios did not violate LOLE.

At-Risk-for-Underperformance

A low composite reliability index indicated that a portfolio either did not exhibit or only partially exhibited several of the generator reliability attributes across the four operational states. As a portfolio's ability to provide the generator reliability attributes decreased, the risk of that portfolio underperforming increased. Portfolios in this category were highly likely to necessitate additional technology requirements and/or new market rules to ensure adequate reliability services. Therefore, portfolios unable to provide at least 90 percent of the composite reliability index of the baseline portfolio were considered at-risk-for-underperformance.

A majority of the portfolios with composite reliability indices low enough to be categorized as at-risk-for-underperformance were portfolios in which most of the coal and nuclear units are retired and replaced primarily by wind. These portfolios tended to underperform in three of the four studied operational states: base load, extremely hot and extremely cold weather. This poor performance was generally driven by low measured capability of these portfolios to provide Synchronous Inertia, Voltage Control, Ramp Capability and Fuel Assurance.

Less-Than-Baseline

The less-than-baseline category was comprised of more than 50 percent of the portfolios, all of which had composite reliability indices within 10 percent of the baseline. Portfolios within this category tended to have relatively low reliability indices under the two extreme weather scenarios, but better performance under the other two operational states. These portfolios were less equipped to provide the reliability attributes, but still benefited from strong performance of several resources in providing the generator reliability attributes.

The performance of portfolios in this category was largely due to the incremental replacement of coal with increasing unforced capacity shares of solar or wind, and a moderate share of natural gas. Unlike coal, these resources either did not exhibit, or only partially exhibited generator reliability attributes that are stressed during extreme weather conditions such as Ramp Capability and Fuel Assurance. These portfolios were not classified as at-risk-for-underperformance, but they did not provide the same level of generator reliability attributes as the baseline. A trend toward portfolios that fall within this category would indicate that PJM and its stakeholders should consider new technology requirements and market rules to address potential operational reliability shortfalls.

Greater-Than-Baseline

Portfolios in the greater-than-baseline category were those with composite reliability index values higher than 1.00. These portfolios had increased capability to provide the generator reliability attributes than the baseline because of the operational characteristics of the resources in those portfolios. It is unlikely that these portfolios will have reduced capability to provide generator reliability attributes under the four operational states. Therefore, they were not likely to necessitate additional technology requirements or new market mechanisms to incent adequate generator reliability attribute capability.

This category represented 21.4 percent of the analyzed portfolios and was generally composed of portfolios in which coal and natural gas[78] accounted for majority unforced capacity shares with moderate levels of nuclear, solar and wind

[77] The composition of each portfolio within the performance categories is graphically depicted in the Appendix.

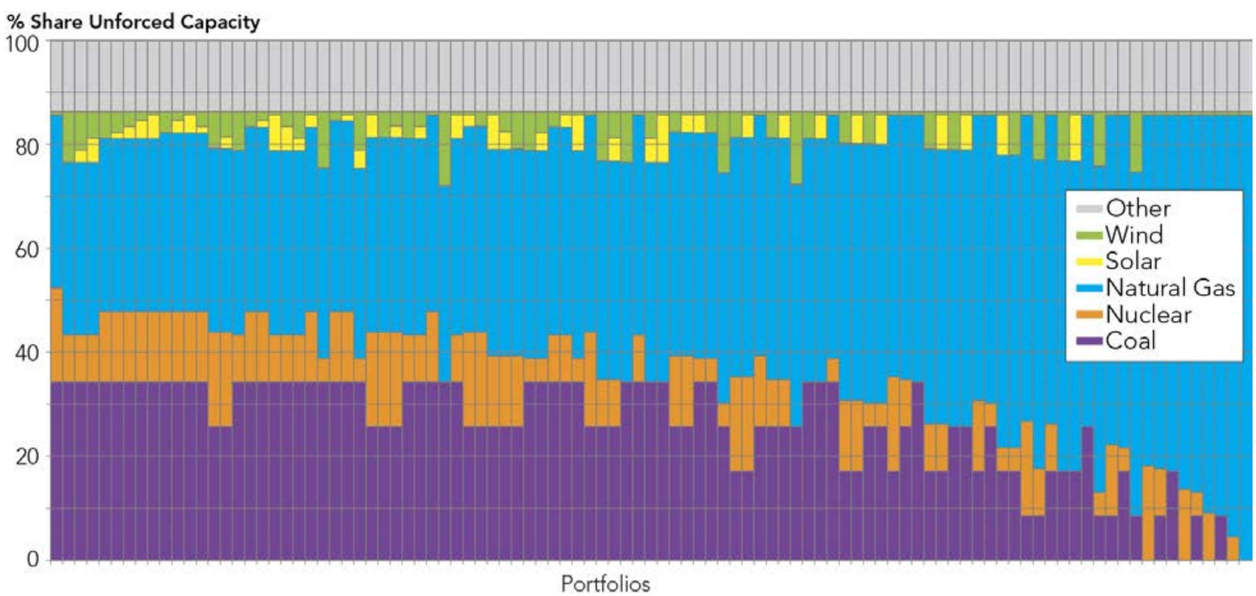
unforced capacity. Gains in generator reliability attribute capability were due to the fact that the predominant resources in the greater-than-baseline category – natural gas and coal – collectively exhibited the majority of generator reliability attributes displayed in Figure 6. The attribute shortcomings of natural gas and coal were met by other resource types in a portfolio. For example, natural gas has reduced capability for onsite fuel because it is extremely dependent on delivery infrastructure, while nuclear has ample onsite fuel capability. Coal units have reduced capability for Flexibility attributes, but are in portfolios with other resources that have shorter minimum run times and shorter startup times.

"Desirable" Portfolios

Under some circumstances, a portfolio's high composite reliability index was due to over-performance in one or more of the operational states, despite under-performing under another operational state. Therefore, portfolios that consistently exhibited high levels of the generator reliability attributes under each operational state were considered best equipped to provide the generator reliability attributes. Portfolios that had the capability to provide 95 percent or more of the baseline's capability under each studied operational state were categorized as desirable.

Twenty-seven percent of the studied alternative portfolios met this criterion. Figure 12 depicts the composition of the desirable portfolios.

Figure 12. "Desirable" Portfolios



Natural gas and, to a lesser degree, coal, individually exhibit a broad range of the generator reliability attributes. Therefore, portfolios with large shares of both natural gas and coal exhibited a majority of the generator reliability attributes. As a result, these resources tended to represent a majority unforced capacity share in the portfolios classified as desirable. However, coal and natural gas did not fully exhibit all of the generator reliability attributes and benefited from the addition of wind, solar and nuclear unforced capacity. Thus, most of the desirable portfolios were composed of relatively large

[78] Natural gas resources within each portfolio include both steam and combustion turbines in the same ratio as the baseline expected near-term portfolio: 60 percent and 40 percent, respectively.

unforced capacity shares of coal and natural gas, with moderate unforced capacity shares of wind, solar and nuclear to provide the full range of generator reliability attributes.

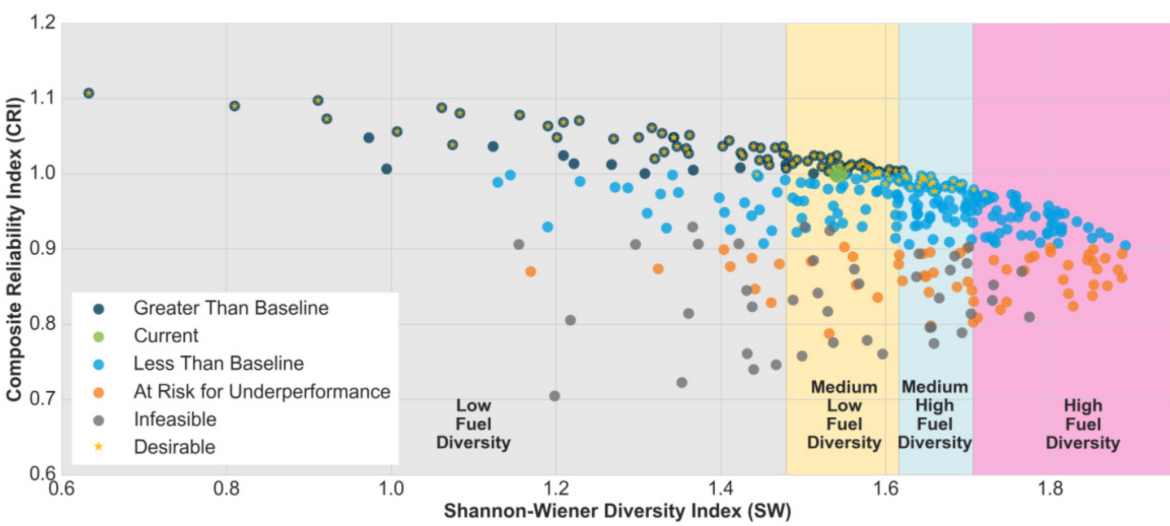
Because wind and solar exhibited limited capability in providing certain generator reliability attributes, upper bounds for wind and solar unforced capacity shares were identified within the desirable category. The upper bound for wind occurred in a portfolio in which a large unforced capacity share of nuclear was retired and replaced exclusively by unforced capacity of wind and natural gas. Similarly, the upper bound for solar within the desirable category occurred in a portfolio in which a large unforced capacity share of nuclear was replaced exclusively by solar and natural gas unforced capacity. Note that, to be included in the desirable category, portfolios with moderate unforced capacity shares of wind and/or solar required relatively large shares of both coal and natural gas. Although an upper bound was identified for wind and solar, a number of portfolios with unprecedented wind and solar unforced capacity shares in PJM were included in the desirable category.

Natural gas generation, on the other hand, performed well across a broad range of reliability attributes. Specifically, the potential portfolio with the greatest share of natural gas, 86 percent, showed no decreases in performance under the four operational states and was included in the desirable category. As mentioned earlier, portfolios composed of natural gas unforced capacity shares greater than 86 percent were not considered in the analysis because they were implausible. Therefore, a performance-based upper bound for natural gas was not identified by the analysis. Operational risk with respect to natural gas, however, may exist in other aspects not considered by this risk analysis. These aspects include infrastructure, economics, policy, and resilience.

Composite Reliability Index and the Shannon-Wiener Diversity Index

To better understand the relationship between fuel diversity and reliability, the composite reliability indices were analyzed against the Shannon-Wiener Diversity Index. Figure 13 displays the relationship between the Shannon-Wiener diversity indices and the composite reliability indices.

Figure 13. CRI vs. Shannon-Wiener Diversity Index



Fuel diversity alone is not an indication of reliability. Because not all fuel types have the same capability to provide the generator reliability attributes, the relationship between fuel diversity and the generator reliability attributes is dependent upon the composition of the fleet. As depicted in Figure 13, several portfolios with low diversity had high composite reliability indices. However, there were also many portfolios with low diversity that had low composite reliability indices.

The capability of capacity resources to exhibit the full range of generator reliability attributes determined the reliability of a portfolio, rather than how many fuel types were in a portfolio or how balanced the share of unforced capacity was among the fuel types.

Fuel Security and Resilience

Although resource portfolios with low diversity may have high reliability indices because they are likely to provide adequate amounts of the defined key generator reliability attributes, "heavy" reliance on one resource type raises questions about electric system resilience, which are beyond questions about already-accepted measures of reliability attributes as have been discussed in this paper. Resilience is the capability of an energy system to tolerate disturbance and to continue to deliver energy services to consumers.

History has shown that, despite having a system that meets reliability standards and requirements, rare extreme events, such as those experienced in PJM and other parts of the world, may produce negative impacts to the system that threaten the ability to continue to deliver energy services. Such events may trigger higher-than-average unit unavailability rates that are not captured by the reliability risk analysis. Therefore, PJM analyzed for a polar vortex[79] sensitivity to show an example of such an impact. This sensitivity analysis is described in Appendix IV: Risk Analysis.

The resilience of the portfolios identified as desirable by the risk analysis was tested by subjecting the desirable portfolios to a polar vortex event. Such an event may trigger higher-than-average unavailability rates for fuel types such as natural gas, coal and solar. To determine these potential higher-than-average unavailability rates, generator performance data from high load days during Winter 2014/2015 and Winter 2015/2016 were analyzed by fuel type. The maximum unavailability rates during those days were applied to the portfolios in the desirable region. Reliability indices and composite reliability indices were recalculated.

Only 34 of the 98 portfolios which were classified as desirable were resilient when subjected to a polar vortex event. This sensitivity specifically captured the increased risk of natural gas delivery under extremely cold and high load conditions. The polar vortex sensitivity highlights the importance of resilience, which is not captured by the generator reliability attributes that were considered in this study.

A resilient energy system can anticipate, minimize the impact of and quickly recover from shocks. It also can provide alternative means of satisfying energy service needs in the event of changed external circumstances.[80] In addition to delivering energy services reliably during strained system conditions to which probabilities can be attached (e.g., plant outages, weather variability), a resilient energy system also must be resistant to larger scale shocks to which it is difficult to attach probabilities and that can exceed NERC planning N-1-1 and operations N-1 criteria.[81] [82]

[79] Large portions of the United States experienced abnormally low temperatures caused by a polar vortex in early January 2014. Coinciding with the hour of peak demand, on January 7, approximately 22 percent of total generation capacity in PJM was not available.

[80] http://www.ukerc.ac.uk/publications/building-a-resilient-uk-energy-system-research-report.html

[81] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=TPL-001-4&title=Transmission System Planning Performance Requirements&jurisdiction=United%20States

[82] During real-time, the electric system must be operated so that it can continue to operate reliably following the failure of any one element on the system, e.g., a generating unit or a transmission line. For planning purposes, the grid must be planned and built so that it is capable of withstanding the unexpected loss of one transmission element followed by the loss of a second element.

Ultimately, the most desirable portfolios are those portfolios that are able to adequately supply all generator reliability attributes and that show resilience in the face of other risks associated with rare extreme events.

Previous Natural Gas and Renewables Studies

Owing to the increased natural gas dependency, PJM, ISO-New England, the Midcontinent Independent System Operator, New York ISO, the Ontario Electric System Operator and the Tennessee Valley Authority, part of the Eastern Interconnection Planning Collaborative (EIPC), with the financial support of the U.S. Department of Energy, commissioned an independent analysis of the robustness of pipeline infrastructure in their regions to meet future electric demand under a variety of scenarios. The EIPC's Gas-Electric System Interface Study,[83] completed in 2015, represented a first of its kind comprehensive analysis of the gas infrastructure's capability to serve the future needs of electric generation over a region that encompasses 35 states and the province of Ontario.

Overall, the EIPC analysis demonstrated that, even under a high-gas-demand scenario, a robust pipeline infrastructure is available through 2023 to serve generation through the overwhelming majority of the PJM footprint. Limited potential locational constraints were identified during the peak heating season in eastern PJM, with most issues associated with generators dependent on the local gas distribution company. Modeling of gas-side contingencies, such as a pipeline break, found that affected generators were spread across many pipelines, thus limiting the impact of a single contingency. Additionally, dual-fuel capability was found to be available, deliverable and economically advantageous in PJM, providing additional resilience to mitigate the risk of gas pipeline contingencies on the electric grid. Although, the EIPC analysis found a robust infrastructure from a physical viewpoint, it also highlighted notable differences between the available infrastructure and the contractual availability and allocation of that infrastructure to meet the needs of the power generation sector.

PJM studied as well the potential impacts of increased dependence on renewable resources, specifically solar and wind. The PJM Renewable Integration Study,[84] conducted by GE Energy Consulting in 2014, investigated operational, planning and energy market effects of large-scale wind/solar integration and made recommendations for possible facilitation/mitigation measures. The study found that "the PJM system, with adequate transmission expansion and additional regulating reserves, will not have any significant issues operating with up to 30 percent of its energy provided by wind and solar generation." Recommendations were made to increase the regulation requirement to compensate for the increased variability resulting from wind and solar generation, develop a methodology to adjust renewable capacity market value, improve the wind and solar forecast through use of mid-range (shorter-term) forecasts, and explore improvements to ramp-rate capability of the existing base load fleet.

Risks to Resilience

Grid resilience is increasingly important considering the number of associated risks – cybersecurity, more extreme weather events, increasing dependence on natural gas pipelines, aging infrastructure and resource category retirements. Add to those more reliance on the internet of things,[85] data and interconnected systems, which create an increased risk of cyber incidents. Preparedness, hardening, robustness, redundancy and autonomy are all components of a comprehensive view of grid resilience.

[83] Information and documents regarding the EIPC Gas-Electric Interface Study: http://www.eipconline.com/gas-electric.html

[84] PJM Renewable Integration Study information and documents: http://www.pjm.com/committees-and-groups/subcommittees/irs/pris.aspx

[85] Internet of things - http://www.mckinsey.com/industries/high-tech/our-insights/the-internet-of-things

Although PJM's established planning, operations and markets functions should ensure that future portfolios would maintain adequate levels of reliability services and fuel security, external drivers – such as economics and public policies – have impacted, and could further impact, the mix of resources in the future. The resource mix could evolve in a way that results in less-than-adequate generator reliability attributes and fuel security because a vast majority of resources could be unavailable because, collectively, they rely either on a single technology or a single fuel.

While redundancy in technology or fuel source helps to mitigate this risk, backup or dual fuel capability currently tends to be limited to supporting sustained operation for a matter of days and, therefore, is dependent on resupply. However, recent studies, including the Black Sky/Black Start Protection Initiative, suggest that 30 days of fuel inventory would be required to adequately respond to Black Sky type events.[86] Although practical for nuclear, oil and coal resources, such a requirement would be a more significant challenge for natural gas plants, which could become a challenge in the future. With no identified maximum plausible penetration of natural gas resources that reach the point of presenting reliability concerns (see the Risk Analysis section above), natural gas resources could continue to replace uneconomic coal and nuclear units at very high levels. While these high levels of natural gas capacity do not suggest direct reliability issues, a very high dependence on one fuel type may create other resilience issues, such as those vulnerabilities identified by the natural gas industry, as discussed later in the paper.[87]

Role of Capacity Performance

In April 2015, in an effort to address the risks of fuel security associated with individual generating plants, PJM revised how capacity resources were defined and compensated in the capacity market. The new capacity product, called Capacity Performance, incents generators to commit to more stringent performance requirements. This includes the "firming" of fuel supply (through firm gas service contracts, firm service contracts with greater flexibility or the installation of dual-fuel capability), as well as investment in operations and maintenance to shorten minimum run times and increase operational flexibility. However, while Capacity Performance improves individual generator availability, to be resilient PJM must take account of the possibility of larger-scale disruptions of the natural gas supply system.

The Capacity Performance product was introduced in response to several changing conditions on the grid – including an unprecedented fuel switch from coal to natural gas and sharply lower wholesale electricity prices, which inhibited needed investments in plant maintenance, upgrades and modernization – all of which profoundly affected the availability of generation, particularly during cold weather. PJM's studies of generator performance during the cold weather of January 2014 highlighted that changes were needed in performance requirements, incentives and charges for non-performance to ensure adequate availability during peak days.

PJM has been transitioning into the Capacity Performance construct since 2015 by procuring more of the Capacity Performance product with each annual Reliability Pricing Model (RPM) Auction. In the 2017 RPM Base Residual Auction for the 2020/2021 Delivery Year, 100 percent of the capacity procured will be Capacity Performance. While there has not yet been an operational test of this new product, PJM has seen improved operational flexibility in capacity resources and increased investment by generators to meet the stricter performance requirements. These improvements map to some of the attributes identified in the Generator Reliability Attributes Matrix, such as fuel assurance and flexibility.

[86] EIS - The Black Sky/Black Start Protection Initiative (BSPI™), http://www.eiscouncil.com/App_Data/Upload/BSPI.pdf

[87] DOE – AGA - Natural Gas Resiliency - https://energy.gov/sites/prod/files/2015/01/f19/AGA.Resiliency%20Metrics%20workshop.pdf

Through stricter performance requirements, incentives and charges for non-performance, Capacity Performance holds capacity resources accountable to make the necessary investments and operational improvements required to ensure delivery of energy when needed most. For example, these investments include firming fuel supply, investing in dual-fuel capability (which combines back-up oil fuel with primary natural gas fuel), increased staffing, capital investments for better operational flexibility, and cold-weather testing on alternate fuels. These investments are based on risks to performance that a resource can anticipate, plan for, budget for and implement.

Capacity Performance is, therefore, designed to address the risks of fuel security associated with individual generating plants by incenting the “firming” of fuel supply through firm gas service contracts, or firm service contracts with greater flexibility, or the installation of dual fuel capability, which combines back-up oil fuel with primary natural gas fuel. The flexibility of dual fuel units has to be balanced with the additional emissions restrictions and this will require continued collaboration with affected resources and regulatory agencies such as the Environmental Protection Agency. However, in order to be resilient, PJM needs to take account of the possibility of larger-scale disruptions of the natural gas supply system.

Although Capacity Performance places the risk of non-performance squarely on the generator – even for events occurring outside the control of the generator (such as loss of fuel supply due to pipeline ruptures or localized extreme weather events), the risks generators assume are those that are captured within the sphere of traditional NERC standards (i.e., N-1-1 planning or N-1 operational events). However, another set of systemic risks can affect the entire fleet and are beyond those traditional NERC standards. While PJM currently studies some of these types of contingencies in planning and operations, consistent with NERC standards, PJM also should examine plausible actions based on potential systemic risks, which are characterized as high-impact, low-probability events, the occurrence of which cannot be predicted with certainty and are beyond what any one resource reasonably can anticipate and mitigate through capital investments and operational improvements. Given the changing nature of the fleet and a new set of threats that were not anticipated under the current NERC standards, prudent planning and operations requires the anticipation and mitigation of potential future occurrence of events, such as:

- sustained supply-chain issues
- environmental actions that limit operations of an entire fleet of fossil generators
- a nuclear disaster, which causes regulatory reaction for new and existing nuclear fleet
- a single incident causing major, multiple pipeline or supply disruptions for the natural gas fleet or oil fleet
- a major impact to a large portion of the transmission infrastructure that forces an outage lasting for days, such as a major natural disaster that impacts large sections of grid including resources and the infrastructure that connects the resources to consumers

Extreme Contingencies and Resilience

Capacity Performance has appropriately placed a degree of risk of non-performance on generators – irrespective of whether the driving factor was technically within the generator’s control or involved its own facility and potentially others near it. Nevertheless, the high-impact systemic events described above also need attention. Currently, NERC does not require mitigating common mode failures or natural gas interdependency risks. NERC defines an N-1 contingency based on the failure of a single piece of equipment or equipment electrically connected.[88]

Resilience, in the context of the bulk electric system, relates to preparing for, operating through and recovering from a high-impact, low-frequency event,[89] such as those listed above. Resilience is remaining reliable even during these high impact, low frequency events. For PJM, resilience means the ability of the system to withstand or timely recover from high risk events beyond the control of individual generators and ensuring sufficient system flexibility in light of a changing generation mix.

To develop a resilient bulk electric system that will operate reliably in response to and be resilient in the face of a wide range of probable contingencies, NERC standards require Planning Coordinators and Transmission Planners to analyze extreme events, such as loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. Currently, if such an analysis concludes there is a probability of cascading outages caused by the occurrence of extreme events, an evaluation is conducted of possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s).[90] The NERC ERO Reliability Risk Priorities report[91] identifies additional risk scenarios that should be assessed but go beyond current NERC criteria. While some of these additional risk scenarios may result in developing standards, many are recommended as assessments only. These risks include changing the resource mix, bulk-power system planning, resource adequacy and performance, extreme natural events, physical security and cybersecurity vulnerabilities. Some themes and takeaways from the Reliability Risk Priorities report focus on enhancing resilience and recovery and a focus on natural gas deliverability.

While PJM itself studies many of these extreme contingencies and events, there are no required triggers for taking action outside an actual failure.

As part of the planning process, PJM analyzes 26 such extreme contingencies, reflecting gas pipeline outages or pipeline compressor failure contingencies in the PJM footprint that would result in 1,000 MW or more of generation loss. In addition, PJM analyzes four temperature-threshold gas contingencies, which simulate a local gas distribution company interrupting non-firm natural gas generation customers in order to serve heating demand at a pre-determined temperature threshold. Such extreme contingencies are incorporated into the PJM Winter Peak Reliability Analysis.[92]

PJM also analyzes expected gas pipeline contingencies and any credible disruptive events on the natural gas interstate pipeline system in the operations horizon. This is done as part of seasonal, monthly and ad hoc assessments to provide

[88] http://www.nerc.com/files/concepts_v1.0.2.pdf

[89] NERC High Frequency, Low Impact Report – June 2010 - https://energy.gov/sites/prod/files/High-Impact%20Low-Frequency%20Event%20Risk%20to%20the%20North%20American%20Bulk%20Power%20System%20-%202010.pdf

[90] NERC TPL-001-4 R3.5 http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=TPL-001-4&title=Transmission%20System%20Planning%20Performance%20Requirements&jurisdiction=United%20States

[91] ERO Reliability Risk Priorities, November 2016 - http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Reccommendations_Board_Approved_Nov_2016.pdf

[92] PJM Manual M14B, Attachment D3 http://www.pjm.com/~/media/documents/manuals/m14b.ashx

situational awareness to PJM Transmission Operations, modeling 50 such contingencies within the PJM Energy Management System.[93]

PJM takes a conservative approach in both planning and operations when defining extreme gas contingencies. The compressor failure contingencies assume that all generation downstream of the gas contingency on the same gas infrastructure is lost, regardless of a secondary gas transmission feed or dual-fuel capability. The temperature threshold gas contingencies assume that all non-firm gas generation in a transmission zone cannot operate due to gas interruption, even if multiple pipelines supply the local distribution company.

In actuality, not all gas units would be lost simultaneously, or instantaneously, as part of such contingencies. The available timeframe for PJM operators to respond to generators coming off line following a gas pipeline contingency can vary significantly as the duration of time is dependent on a variety of factors, including the location and severity of the failure on the pipeline system, the pressure within the pipeline at the time of the incident, the firmness of the gas service the generator procured and whether alternative pipeline transmission is available to the generator. The time period between gas infrastructure failure and a generator coming off line potentially could range from several minutes to several hours in cases where no redundant backup gas supply capability exists and one or more of the factors identified above came into play. If such a contingency were to occur, PJM would start effective non-gas generation, direct some resources to swap to an alternate fuel or request that the generator be serviced from a secondary pipeline (if possible), and quickly implement emergency procedures as necessary to maintain system reliability. Depending upon the location of the gas infrastructure failure in relation to the gas generation, PJM would have several minutes to a few hours to take corrective action in response to a contingency.

A Prudent Approach

PJM meets all of the requirements of the current NERC standards and assesses many of these risk areas in both planning and operations. A prudent approach, consistent with the NERC standard entitled Transmission System Planning Performance Requirements (TPL-001-4 R3.5), would be to take the next step after developing mitigating steps and action plans: implement some of the corrective actions for some of the widespread events in order to enhance the system's resilience and recovery.

PJM will continue to manage potential reliability issues through the system planning processes, either by reinforcing the system with transmission upgrades or by increasing reserve margins to ensure adequate resources are available. PJM and its stakeholders, however, should examine low probability and high impact events which cause significant reliability impacts and consider additional measures to ensure grid resilience.

Moving Forward

PJM's established planning, operations and markets functions have resulted in a resource mix that is reliable. The current resource mix is also diverse – with a combination of natural gas, coal, nuclear, renewables, demand response and other resource types. PJM recognizes that the benefits of resource diversity include the ability to withstand equipment design issues or common modes of failure in similar resource types, fuel price volatility, fuel supply disruptions and other

[93] In addition, through the Eastern Interconnection Planning Collaborative, PJM analyzed the future load forecast compared to the natural gas pipeline infrastructure anticipated to be in service in 2018 and 2023 and then tested that system through analyzing the impact of the largest contingencies on both the pipeline and electric grids. The reviews of that analysis were presented to stakeholders through the EIPC analysis.

unforeseen system shocks. However, external drivers have impacted, and could continue to impact, the makeup of the resource mix.

PJM's analysis shows that, depending on the composition of a resource portfolio, there could be negative impacts to the ability of that portfolio to provide an adequate level of reliability services, because all resource types are not equal in the generator reliability attributes they provide. Resource diversity itself, however, is not a measure of reliability. Relying too heavily on any one fuel type may create a fuel security or resilience issue because the level of resource mix diversity does not correlate directly with a resource portfolio's ability to provide sufficient generator reliability attributes. But, a moderate level of diversity helps to ensure the system's ability to withstand unforeseen system shocks – either operational disturbances caused by contingencies beyond those studied and planned for today or both man-made and natural disasters.

The capability of resource types to provide various generator reliability attributes may change in the future because of changes in technology or regulations. Operations, market compensation and regulatory structures may, therefore, need to shift to provide incentives to ensure that adequate levels of generator reliability attributes are maintained in future resource mixes. PJM will continue to leverage a proven approach of utilizing its well-developed stakeholder process both to ensure future resource mixes support continued reliable operations and to define criteria for resilience.

In parallel with inter-regional and national efforts, PJM and its stakeholders should continue to examine resilience-related low-probability and high-impact events which can cause significant reliability impacts. Resilience is becoming a more prominent topic for the power industry and other industries. As the grid operator, responsible for coordinating the movement of wholesale electricity in all or parts of 13 states and the District of Columbia for more than 65 million people, PJM recognizes its responsibility to actively participate in and/or lead this conversation. Risks are changing and PJM recognizes the need to be part of the discussion to quantify and mitigate these risks

However, unlike the reliability services used in this analysis, criteria for resilience are not explicitly defined or quantified today. Some questions PJM and its stakeholders should consider include:

- Does PJM's current set of business practices ensure that PJM's evolving resource mix will result in continued reliable operations?
    - Are there reliability attributes that are missing from this analysis? What, if any, generator reliability attributes are important but currently being undervalued in PJM?
    - Should all generator reliability attributes have a required quantity? How should this be determined? Based on total portfolio capability? Procured in the day-ahead market? Scheduled as part of real-time dispatch?
    - During high-dependency / high-risk periods, should PJM schedule the system differently to consider fuel security concerns, such as scheduling a unit on its alternate fuel or carry extra reserves?
    - How can distributed energy resources (including demand response and microgrids) and renewable resources provide additional reliability or resilience services through improvements such as improved inverter and storage technologies?
- How could PJM's business practices consider resilience?
    - How should resilience be defined and measured as part of planning and operations?

- Should PJM plan for and operate to a reasonable set of extreme contingencies to provide an adequate operating margin? Under normal operations? Situationally dependent?
- Should PJM and the natural gas pipelines coordinate, study and operate to joint electric and natural gas contingencies?[94] Should PJM also consider this for other critical infrastructure industries such as telecommunications and water?
- Could PJM's black-start requirements and restoration strategy better consider resilience, for example, in how PJM defines black-start resources, critical load and requirements for cranking paths? Are PJM's system restoration plans too reliant on single-unit or single-cranking-path solutions that do not properly account for fuel security and fuel transportation risks?

PJM has a unique perspective to inform these discussions. Based on industry standards, best practices, thought leadership and emerging threats, industry-wide action as well as PJM action is needed.

[94] http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Reccommendations_Board_Approved_Nov_2016.pdf

Fuel Diversity in the New York Electricity Market

A New York ISO White Paper

October 2008

The purpose of this paper is to explore the various meanings of fuel diversity and its impact on the New York electricity market.

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1. Introduction

In today's era of high energy prices, observers often point to improving our fuel diversity and energy independence as ways to mitigate the impacts of fuel price increases on consumers, and improve supply reliability. Calls for greater fuel diversity are now common — whether from elected officials or regulators seeking to buffer their electricity consumers from price increases in global energy markets, or from representatives of the energy industry looking for strategies to mitigate price increases and boost reliability.

The New York Independent System Operator (NYISO) asked Susan Tierney of Analysis Group, Inc., to assist in the preparation of a white paper on fuel diversity in New York's wholesale power market. This paper identifies trends that have led to the electric industry's focus on fuel diversity. It examines various meanings of fuel diversity within an electricity market; discusses various economic, reliability and environmental dimensions of fuel diversity; explores the impacts of various events on fuel or technology-dependent energy systems; looks at approaches used in other regions to address fuel diversity; and identifies options to address fuel diversity that are both well aligned and poorly aligned with New York's electricity markets.

Recent appeals for diversifying electricity supplies stem from several conditions. Most new power plant capacity added in the U.S. in the past decade relies on natural gas to generate electricity. Natural gas prices have increased dramatically over that same period. While the overall percentage of power generated by natural gas increased only modestly nationwide, natural gas price increases have a disproportionate effect on wholesale electricity prices in certain power markets in the U.S, including in New York. These conditions have contributed to recent and heightened calls for actions to diversify our electricity mix.

A common goal among advocates of greater fuel diversity is the hope that diversifying a power system's fuel and technology mix will enable the system to withstand fuel price volatility, fuel supply or delivery disruptions, or technical disturbances on the system. But apart from these rationales, there is little consensus on what "fuel diversity" would look like if we had it. Advocates draw analogies to the well-understood attributes of a diversified stock portfolio, or the common-sense appeal of "not having all of your eggs in one basket."

There can be other motivations. Sometimes, calls for greater fuel diversity are less an appeal to diversity as a goal in itself but rather an indirect statement by one group or another that there is not enough of his or her preferred fuel or power-generation technology in a system's mix. Some observers' calls for greater fuel diversity in an electric system can be interpreted as a somewhat veiled critique, indicating their disappointment with the outcome of market forces.

Another common theme of many fuel-diversity discussions is the link to energy security or energy independence. The point is that a national or regional economy whose energy system is fundamentally vulnerable to strategic actions of others who control a particular fuel or resource is structurally weaker than economies with more robust, balanced, or diverse energy systems.

New York State's overall electric system is actually more diverse than is typically thought. No one fuel is used to generate more than a third of the state's power, for example. In fact, the statewide generation mix could be viewed as more diverse and more balanced than many other states that are much more dependent on coal or nuclear or hydroelectric power.

The statewide picture, though, does not represent different regions of New York's power market. While most of the population and electric load is downstate, much of the state's lower-cost electricity supplies (hydroelectric, wind, nuclear) are located in the upstate zones. Typically, the NYISO cannot fully dispatch all low-priced power production facilities (such as wind) in the upstate region to meet downstate loads because of electrical overloading of the transmission system that would occur with the north-to-south flows on the system. As a result, more expensive plants (gas-fired peaking plants, oil plants) must by physically located downstate, and then operated locally to keep the lights on in New York City and Long Island.

It has been easier to site relatively large and diverse power plants (including hydroelectric, nuclear, coal, and natural gas projects) upstate. Some upstate areas have significant indigenous resources for power generation (e.g., wind and hydroelectric resources). Electricity prices in the upstate zones are much lower on average than in New York City and Long Island. These differing conditions have significant fuel diversity implications for the upstate and downstate areas of New York. Without changes in the infrastructure allowing other generating resources to be available to the downstate region, prices will continue to be shaped by the relatively expensive fossil fuels used there.

In spite of these challenges in the near term, various features of New York State's overall economic, social, and natural resources may provide opportunities for the state to support a more resilient electric system. For example, the New York metropolitan port area has the ability to move energy products in and out of the downstate area. New York's off-shore resources include renewable resources (e.g., off-shore wind, tidal) that could be developed, providing some indigenous sources of power. New York's significant municipal solid waste and demolition waste streams might provide fuel for projects using new gasification technologies that gasify wastes for combustion in power plants. Both downstate and upstate regions of the state are proximate to regional wholesale markets (e.g., PJM, Eastern Canada, ISO New England or ISO-NE) with relatively similar market designs and inter-regional cooperation which offer the prospect for enhanced trade, should infrastructure developments reinforce the interconnections between the regions. While ISO-NE's electric system is highly dependent on natural gas, PJM's and Eastern Canada's are not.

Today's electricity and energy mix in New York is the result of countless decisions by public and private decision makers. Considerations have included a complex array of public policies, economic and technology conditions, capital market conditions, electrical infrastructure layout, consumer preferences, and siting politics highlighted by "not-in-my-backyard" or NIMBYism. As a consequence, today's fuel diversity profile in New York is neither "good," nor "bad," but consists of electricity production, delivery and use which present various risks and/or unanticipated consequences. Even so, the primary consequence of a less than optimally diverse energy resource mix ends up hitting the pocketbook: consumers face the risk of higher and more volatile prices.

If the primary concern about the electric system configuration in the downstate area of New York is economic in nature, what then, are the options available to address fuel diversity, and what are the implications of taking steps to implement them? This paper examines a variety of ways in which public policy makers in New York, as well as the market itself, have responded by diversifying and reinforcing some sources of supply to the industry.

Additionally, the paper explores a number of possible short- and long-term policy options which could change the signals in the market place and/or allow customers and suppliers to better withstand shocks to the system.

Some options described in this paper include:

- Enhancing the ability to operate power plants using alternative fuels
- Increasing the penetration of energy efficiency and other strategies on the customer's premises
- Encouraging hardware and software investments that make the system more resilient and able to deliver non-gas resources to different parts of the state
- Creating incentives for improved hedging to address price volatility
- Introducing regulatory policies and market rules to encourage investments in transmission, generation, communications, fuel delivery, storage, and other infrastructure allowing for a more diverse system
- Putting in place emergency measures to mitigate the effects of certain types of adverse events on the system

Each of these approaches involves trade-offs, and this paper is intended to inform policy makers and other stakeholders of many of the issues as they consider whether and how to address fuel diversity issues in New York State in the future.

2. Background

Given high and rising energy prices, observers often point to improving fuel diversity — as well as energy independence — as a way to mitigate the impacts of recent price increases on consumers. In the past few years, extensive reliance of particular sectors of the economy on specific fuels has become a focus of attention: Price increases in crude oil in 2008 led in part to record-high prices for gasoline in the transportation sector; and rising natural gas prices since 2000 have driven up electricity prices in the parts of the country that are heavily dependent on natural gas to produce power.

Calls for greater fuel diversity are now common, as noted above. The objectives of this paper are to:

- Identify trends that have led to the electric industry's focus on issues surrounding fuel diversity
- Explore and explain various meanings of fuel diversity within an electricity market
- Discuss the sources of and economic, reliability and environmental dimensions of fuel diversity.

This paper will also explore different approaches that other electricity regions have used or are now seeking to address fuel diversity, and the challenges associated with these various strategies; and identify options to address fuel diversity that are well aligned and poorly aligned with New York's electricity markets.

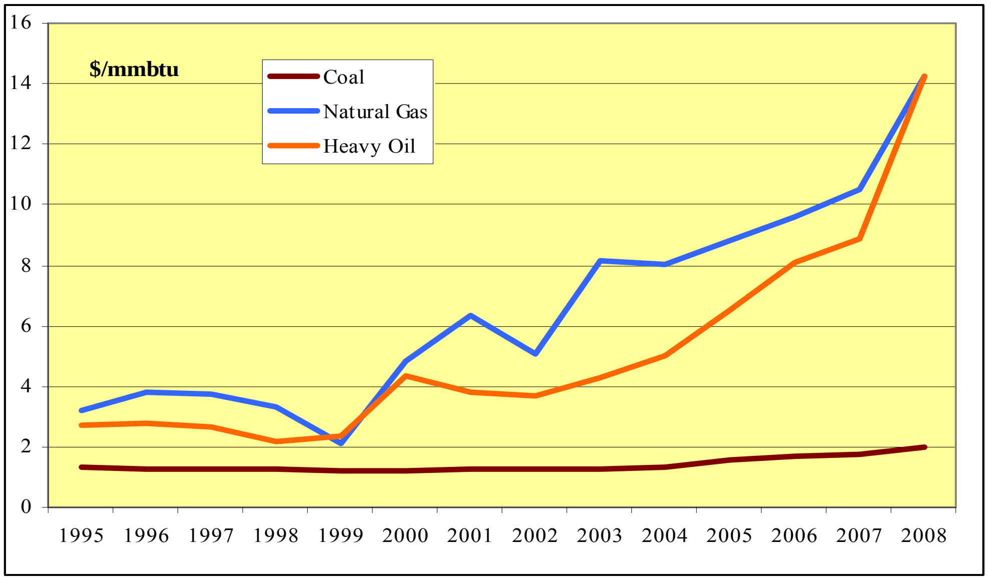
Recent Trends Affecting Fuel Diversity in the Power Sector

Recent appeals for diversifying supply in the electricity sector stem from several developments, including:

1) Natural gas has accounted for 91% of the new power plant capacity added in the United States in the past decade. Natural-gas fired combined cycle power plants were the dominant choice by developers and investors starting in the mid-1990s, given this technology's low capital costs, relatively high efficiency, low air emissions, relatively fast permitting process, and the outlook (at the time) for continued low prices for natural gas.

2) After remaining relatively flat in the 1990s, natural gas prices for electricity generation have increased dramatically since and have risen nearly seven-fold since 1999. (See Figure 2-1, below.) 3) While the overall share of power generated by natural gas increased only modestly (from 13% in 1996 to 21% in 2007) nationwide, gas price increases have had a disproportionate effect on wholesale electricity prices in certain restructured power markets in the U.S. (such as those in New York, New England, Texas, and much of the Mid-Atlantic and Midwest regions). In these power markets, hourly energy prices are heavily influenced by the price of the fuel used by the marginal power plant in that hour. In many of these markets — notably ISO-NE and Electric

Reliability Council of Texas (ERCOT), and to a lesser degree in the NYISO and PJM — natural-gas power plants are the marginal producers during a high percentage of hours of the year.



Source: Energy Information Administration[1]

Figure 2-1: Fuel Prices to the U.S. Electric Sector – 1995-2008

As of the last quarter of 2007, over 90% of the new fossil-fuel power plants proposed in the U.S. were natural-gas-fired power plants. As of the summer of 2008, the Energy Information Administration (EIA) estimated that average natural gas prices in 2008 would be 60% higher than they were in 2007.

These conditions have contributed to recent and heightened calls for actions to diversify our electricity mix. In the recent appeals for greater fuel diversity, one thing is clear: there is no common definition of what the concept means.

Defining Fuel Diversity

Customarily, enhancing "fuel diversity" means adding variety to a power system's fuel and technology mix in order to enable the system to withstand fuel price volatility, fuel supply or delivery disruptions, or technical disturbances on the system.

A typical example of what "fuel diversity" means can be found in the position of many of the nation's electric utility regulators. The National Association of Regulatory Utility Commissioners (NARUC) recently passed a resolution encouraging "state commissions and other policy makers to support the concept of fuel diversity for electric generation." Concerned about the increasing dependence of the nation's generation mix on natural gas at a time of rising prices, NARUC's 2004 Resolution on Fuel Diversity called for a "reliable and balanced long-term fuel mix" for power production.[2] In a prior resolution on national electricity policy, NARUC supported actions and policies to "assure adequate, reasonably priced, reliable, safe, and environmentally sound electricity." To achieve this goal, NARUC called for federal legislation to encourage (among other things) "diverse, plentiful and environmentally responsible energy supplies," with "additional fuel- and technology-diverse supply resources to meet the nation's growing energy demands."[3]

But apart from these appeals for fuel diversity, there is little consensus on what it ought to entail.

Kenneth Costello of the National Regulatory Research Institute, for example, has stated that "the primary justification for fuel diversification lies with the objective of reducing risk, a strategy parallel to investors' diversification of their financial assets to achieve tolerable risk and, at the same time, earn reasonable returns."[4] He argues that ideally, a 'portfolio' of generation technologies would be such that the various fuel prices are not correlated and move in opposite directions to nullify each other's volatility by creating a hedge against volatile and uncertain fuel prices — much like how a financial portfolio would be structured. Understandably, there are certain types of risks that affect fuel prices (such as macroeconomic conditions) that are not likely to be mitigated through a fuel-diversification strategy.

Sometimes, calls for greater fuel diversity are attempts to promote a particular fuel in a system's power-generation technology mix. There are many familiar examples, whether from pro-nuclear, or pro-coal, or pro-renewables partisans, each of whom may view the recent movement toward dependency on natural gas as disfavoring these other resources.

Some observers' calls for greater fuel diversity in an electric system can be interpreted as a somewhat-veiled critique, indicating their disappointment with the outcomes of market forces. In other words, given the role of markets in our energy industries, whatever level of fuel/technology diversity that exists in an electric system at a point in time is likely to be the result of rational responses of countless public and private decision-makers to the constellation of market, regulatory, tax, and other policy signals existing at the time these myriad decisions were made. The past decade's significant investment in natural-gas-fired generating capacity could be seen as sensible responses of innumerable private and public actors to conditions in fuel markets, restructured electricity market design and policy, permitting and environmental policies of states and the federal government, opportunities in financial markets and the risk appetite of various players. While some of the signals — such as natural gas prices — changed over time in ways that made the investment outcomes less attractive for some market participants (e.g., consumers, state elected officials, even some investors), the individual decisions that led many regions to become more dependent upon natural gas may not have been unreasonable at the time, given the signals in the marketplace.

In fact, without interventions that modify some of those signals, it may not be reasonable to expect future investment patterns to lean significantly toward a different fuel and technology mix than has been seen in recent years. Thus, without changes in such things as the public's appetite to tolerate the siting of new nuclear generating capacity, or new policies that encourage long-term contracting and/or new subsidies for advanced coal-fired generation technologies, or the adoption of policies that put a price on carbon emissions, one might continue to see investor interest in natural-gas-fired generating projects in many parts of the country. (These issues are discussed in greater detail in subsequent sections of this paper.)

Finally, a common theme of many fuel-diversity discussions is the link to energy security or energy independence. The popular version of this argument is often voiced by elected officials, who advocate that our energy systems should be free from reliance on imported fuels. The standard target of this view is our oil-dependent transportation sector, but the perspective has arisen in discussions about growing reliance on natural gas in the power sector and its implications for an increasing dependency on imported liquefied natural gas (LNG) from countries with a history of withholding energy supplies for political purposes, for example Russia.

While there are sophisticated and sometimes spirited debates over the strengths and weaknesses of the energy independence argument, there is one strong argument that seems relevant for this paper's discussion of fuel diversity in the power sector. This is the point that a national or regional economy whose energy system is fundamentally vulnerable to strategic actions of others who control a particular fuel or resource is structurally weaker than economies with more robust, balanced, or diverse energy systems. In this view, an "energy independence" strategy is not one aimed at cutting a country or a region off from its ties (and imports) from others; rather, it is a strategy of stripping a particular fuel from its strategic value.[5] In this view, a region may use a variety of strategies to diversify its energy sources, making the country less vulnerable to the strategic geo-political-economic actions of a particular set of sovereign or commercial actors. As described in greater detail in a later section of this paper, such actions might involve:

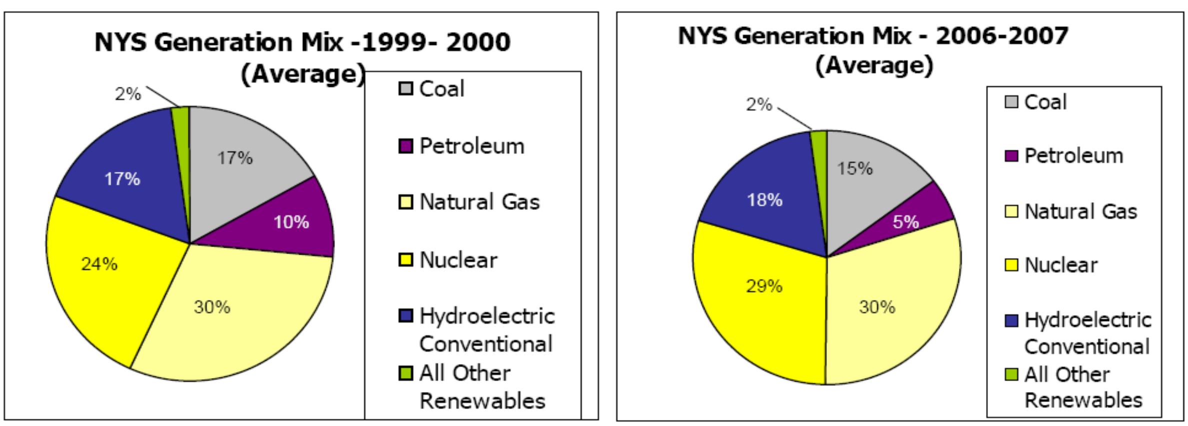
- Diversifying of the sources of supply of a fuel (e.g., pipeline additions and LNG terminals that allow a region to draw natural gas supplies from a variety of gas-supply basins and suppliers)
- Enhancing the ability to rely on fuel substitution (e.g., plug-in hybrid electric vehicles as a replacement for gasoline-powered automobiles, or biofuels to blend into gasoline supplies, or adding dual-fuel capability to a single-fuel power plant)
- Diversifying the array of resources used in a particular sector (e.g., developing a deliberately broad portfolio of power generation technologies that rely on different types of fossil and non-fossil fuels, and distributed and central-station generation systems)
- Relying on a network of infrastructure that allows subregions of a larger area to call upon resources from a neighboring region when a particular action affects one area and not the other (e.g., building a high-voltage transmission overlay system to interconnect various sub-regions, and to allow greater trading and interdependence among the regions)

Perspectives on Fuel Diversity

All electric systems have some inherent attributes of diversity with respect to fuel, and all electric systems end up with a particular mix of generation resources that more or less reflects the technical requirements of satisfying their loads. But this aspect of fuel diversity is not what most of us have in mind when we consider whether or not an electric system is diverse. We take for granted that functional diversity will exist in just about every electric system, and look beyond it to determine whether the system is composed of a diverse — that is, varied, balanced, or robust — set of resources from a fuel mix and/or technology and/or locational perspective.

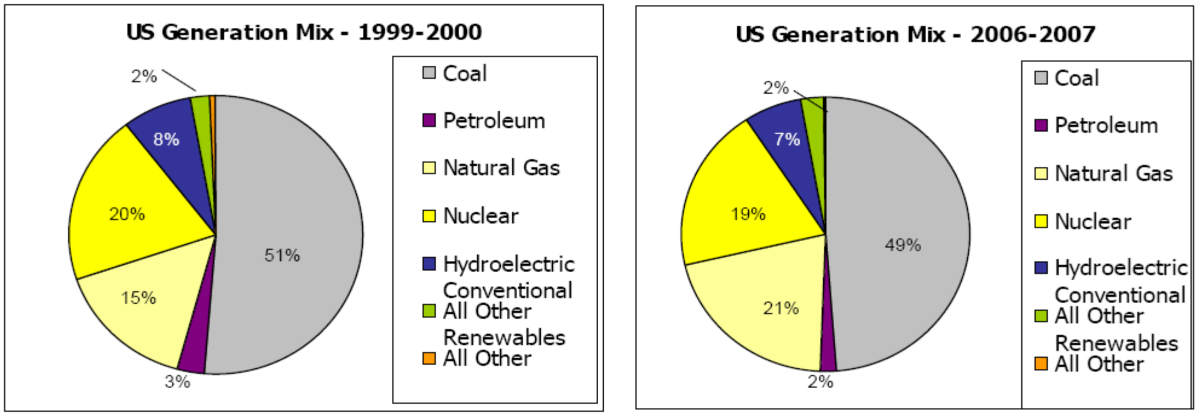
Focusing on these features, what systems do we conventionally think of as being diverse from a fuel, technology, and/or locational point of view? New York's electric system may not be the first that comes to mind, yet from a statewide perspective, its generation mix is relatively diverse. And counter to conventional wisdom, New York State's fuel mix in recent years (2006-2007) is roughly the same as it was at the time the NYISO began administering the wholesale power markets (1999). In 1999-2000, natural gas had the highest share of generation (30%), followed by nuclear (24%), conventional hydro (17%), coal (17%), petroleum (10%), and other renewables (2%). The mix more recently (2006-2007) is roughly the same, with a somewhat smaller share of petroleum (5%) and somewhat larger share of nuclear (29%), but about the same percentage output from natural gas, hydro and coal.

Comparatively, the U.S.'s overall generation mix is less diverse than New York's in both periods, with a much higher percentage of power from coal (with the U.S.'s dependence on coal roughly three times that of New York's), and less power from natural gas, nuclear and conventional hydropower. Using these data to contrast the two power systems, New York's might be considered *more* balanced from a fuel diversity point of view, as summarized in Figures 2-2 and 2-3.



Source: EIA, 902 Electric Generation Data

Figure 2-2: New York State Generation Mix



Source: EIA, 902 Electric Generation Data

Figure 2-3: US Generation Mix

In contrast, the ISO-NE's system, which is well-known for its dependence on natural gas, had 40% of its generation in 2007 fueled by natural gas. While ISO-NE's generation is the least balanced electrical region in the Northeast from a fuel-diversity point of view, its dependence on a single fuel — i.e. natural gas — is relatively moderate as compared to a large fraction of the nation. Some prime examples of generation mixes being highly reliant on a single fuel are:

- Natural Gas: Nevada – 67 %; Alaska – 57 %; California – 55%; Texas – 49%; Louisiana and Oklahoma – 46%; Florida – 45% [6]
- Coal: West Virginia – 98 %; Wyoming – 95 %; Indiana and North Dakota – 94 %; Kentucky – 93 %; Ohio – 86 % [1],[7]
- Hydroelectricity: Idaho – 79 %; Washington State – 73 %; Oregon – 62 %
- Nuclear: South Carolina – 51%; Illinois – 48%

The apparent lack of attention being paid to the high dependency of regions on coal, nuclear, or hydroelectric power might reflect that policymakers' and regulators' concerns about fuel diversity are more than offset by economic factors since electricity prices are largely driven by fuel prices. This indicates that policymakers, regulators, and others may be less concerned with fuel diversity *per se* than they are with some other factors, such as the extent to which electricity prices — or, rather, changes in electricity prices — are driven by conditions affecting a particular fuel and/or power plant technology.

Some non-economic factors that might strengthen the case for greater diversity in an electric system are:

[1] These states are: Maryland (50%); Alabama (54%); Pennsylvania (55%); Michigan (59%); Minnesota (60%); Nebraska (60%); North Carolina (61%); Georgia (62%); Wisconsin (63%); Tennessee (64%); Montana (64%); Delaware (66%); Colorado (68%); Kansas (73%); Iowa (77%); and New Mexico (77%).

- A vulnerability with respect to extreme weather events (e.g., extreme drought causing a shift from significant hydropower to other fuels, or a hurricane disrupting oil and gas production capacity)
- Exposure of existing facilities to public policy measures (e.g., a carbon tax that speeds retirements and/or requires extensive capital outlays)
- A supply portfolio with a high percentage of power produced by a few large generating units that may be exposed to simultaneous outages (e.g., an extended outage of multiple large units at a nuclear generating station)
- A single clearing price market with a single fuel dominating the marginal power production curve in a high percentage of hours and where the dominant marginal fuel (e.g., natural gas) experiences high, volatile and/or increasing prices
- An electrical zone within a larger region in which the zone (a) is constrained in its ability to import power from other generators outside the zone and (b) has one or more of the aforementioned attributes

These examples illustrate that the issues affecting the interactions of generation and electricity prices are not only a function of fuel and/or technology diversity, but also market design, technological developments, locational issues, and other factors. What might seem like a relatively diverse electrical mix during one set of conditions may shift rapidly to looking like a region with fuel and/or other types of diversity challenges.

3. Snapshot of New York's Fuel Diversity by Region

Previously, this paper characterized New York State's overall electric system as being relatively diverse compared to its neighboring control areas and considerably more diverse than most states. No fuel is used to generate more than a third of the state's power;[8] and together, four separate fuels each produce over 15% of the power generation.

The statewide characteristics however are not shared by the regions of New York's power market. There are important differences between the generating capacity, technology and fuel mix, and transmission systems in the upstate and downstate regions. These features have different implications for the economics, reliability and other attributes of power supply for electricity customers in different parts of New York.

As shown in Figure 3-1, there are multiple "zones" in New York's electric system. There are several upstate zones (A-I), the New York City zone (J), and the Long Island zone (K). These zones are interconnected electrically by the high-voltage transmission system. Power can move between the zones to the extent allowed by capacity of the transmission network and electrical conditions in various parts of the system at any point in time. That said, there are significant constraints on the ability of power to move from upstate zones to downstate zones, which is the normal direction of flows on the system.

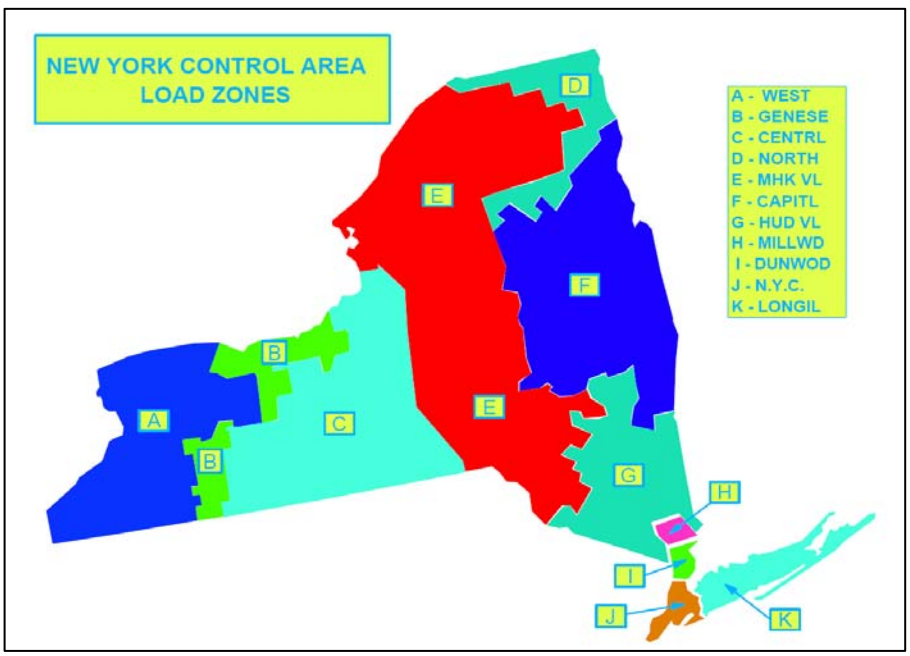


Figure 3-1: New York Control Area Load Zones

These patterns result from well-known realities within the state:

- Most of the population and electrical load is downstate (in the New York City and Long Island zones).
- Much of the state's lower-cost electrical supplies (hydroelectric, wind, relatively efficient gas plants) are located in the upstate zones.
- Typically, the NYISO cannot fully dispatch all low-priced power production facilities in the upstate region to meet downstate loads because of electrical overloading of the transmission system that would occur with the north-to-south flows on the system. As a result, more expensive plants (gas-fired peaking plants, oil plants) located downstate must be turned on to keep the lights on in New York City and Long Island.
- The downstate areas (Zones J and K) tend to be faster growing in terms of electricity use. These are also areas where it has been difficult and expensive to site any types of power plants besides gas-fired power plants. Hence, the heavy reliance on natural gas, exposure to risk of sudden fuel price increases, and considerably higher electricity prices — as compared to the rest of the state. While off-shore wind could be used for renewable generation, developing such projects remains a challenge.
- In contrast, the rest of state (the upstate zones, A-I) has had slower load-growth. Historically, it has been easier to site relatively large and diverse power plants (including hydroelectric, nuclear, coal, and natural gas projects, as shown in Figures 3-2 and 3-3). Some of the upstate areas have significant indigenous resources for power generation (e.g., wind and hydroelectric resources). Electricity prices in the upstate zones are much lower on average than in New York City and Long Island.

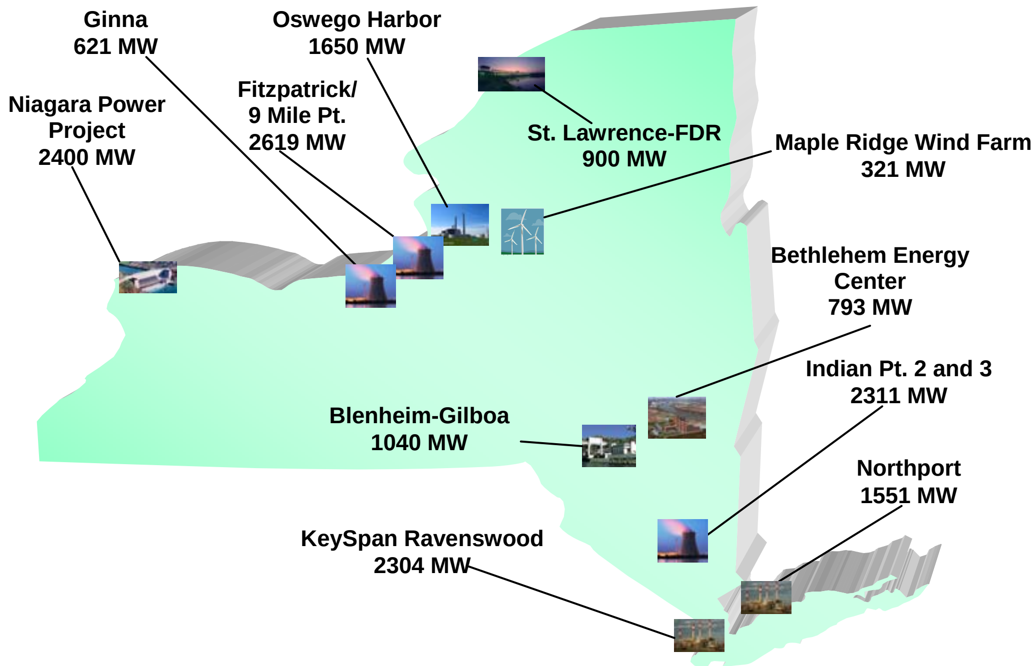


Figure 3-2: Key Generation Facilities in New York State

These differing conditions have significant fuel diversity implications for the upstate and downstate areas of New York. For example, as shown in Figure 3-3, the power plants located in New York City and Long Island are significantly dependent on natural gas and oil. Single-fuel plants using natural gas alone and dual-fuel plants that mainly use natural gas (i.e., dual fuel with air-permit limitations on the amount of generation that can come from oil) make up 95% of New York City's generating capacity and 79% of Long Island's capacity. By contrast, natural gas-only plants make up 15% of the capacity in the rest of New York State, where there are also significant amounts of generating capacity that use lower-cost fuels like nuclear, hydroelectric, and coal.

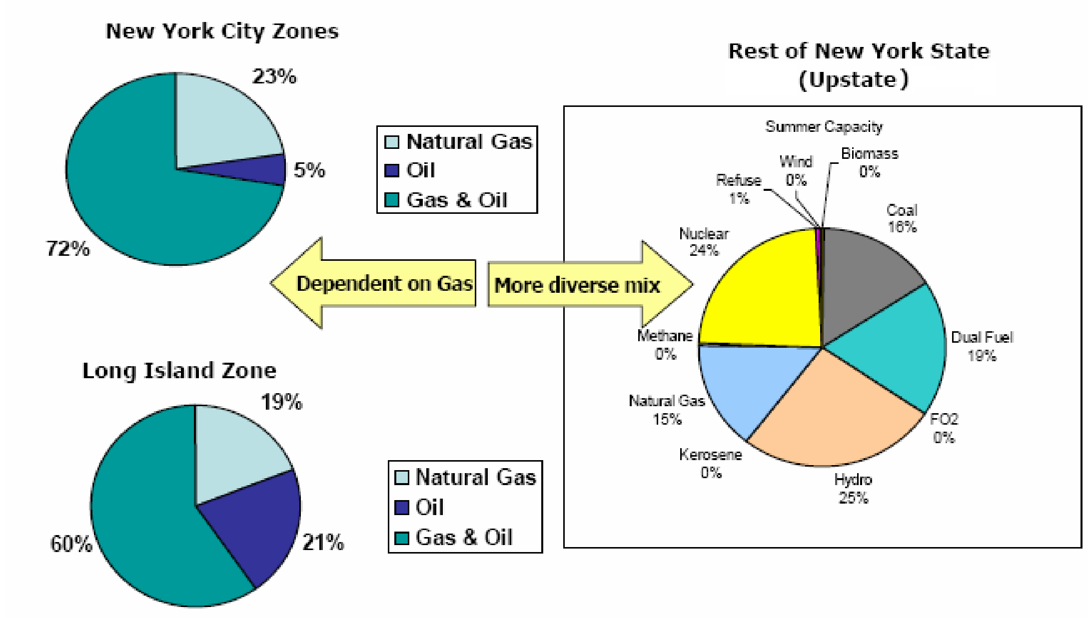


Figure 3-3. Fuel Mix (Capacity) by New York Region

As shown in Figure 3-4, in New York State as a whole, low-cost fuels (i.e., coal or hydro) set the day-ahead clearing price in the wholesale electric energy markets administered by the NYISO in approximately one-sixth of the hours of the year. By contrast, in NYC, in-zone natural gas and oil facilities are setting the price in virtually all of the hours of the year (as shown in Figure 3-5).

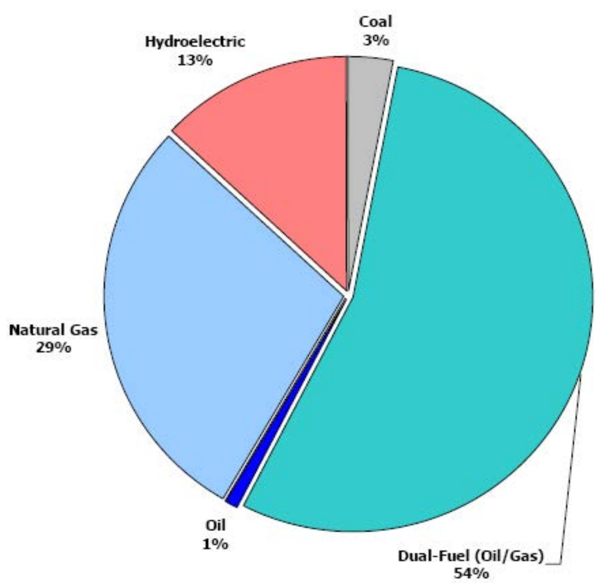


Figure 3-4: Percentage of Hours in Which Energy Clearing Price is Set by Fuel Type – New York (2007)

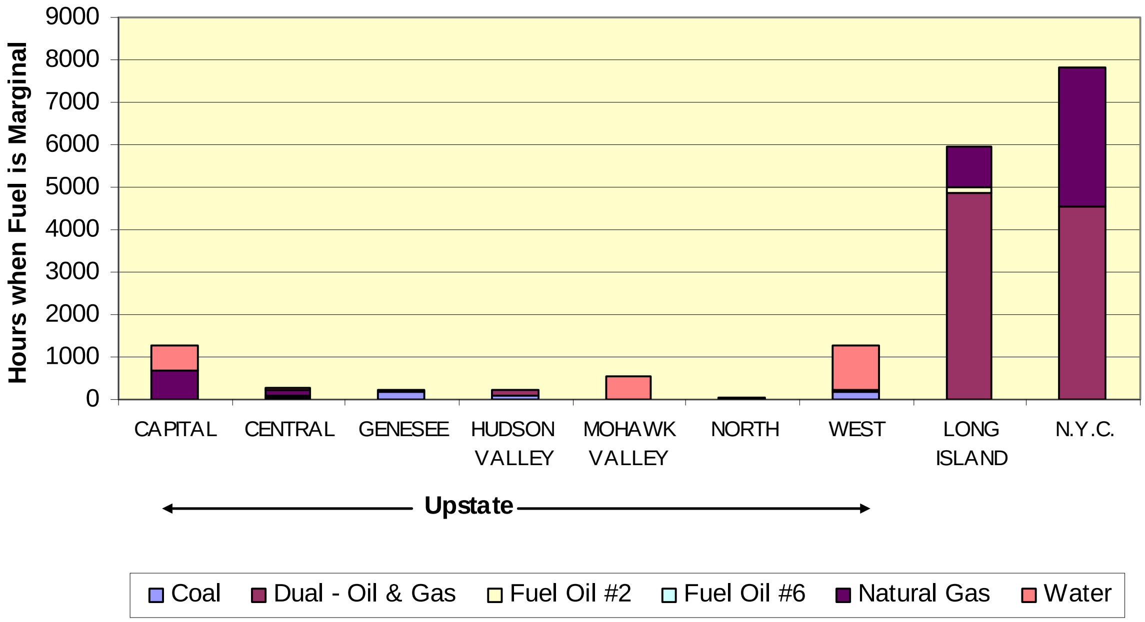
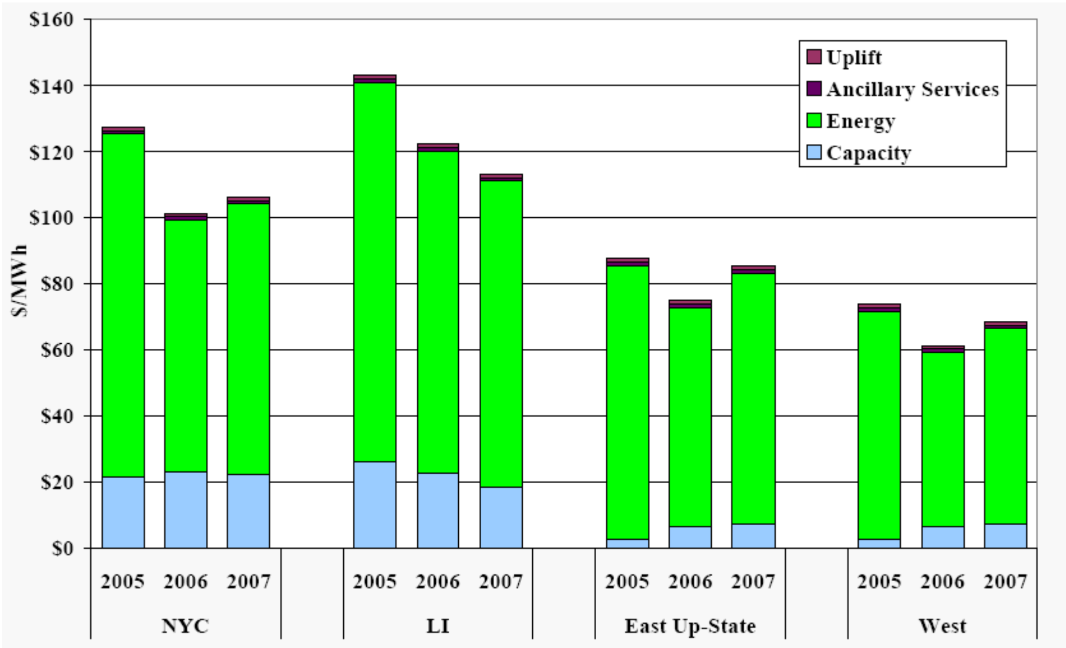


Figure 3-5: Fuel of Marginal Unit by Zone

Transmission constraints prevent "surplus" low-cost power from upstate New York from satisfying demand in downstate areas. That is, while some economic generation that is dispatched in upstate New York goes toward meeting part of the demand in New York City, other low-cost generation cannot be dispatched because transmission lines cannot carry the power downstate. Relatively low-cost power is thus bottled up, and more expensive plants located in the New York City and Long Island zones are needed to meet local loads located in those areas. This keeps wholesale electricity prices higher downstate than upstate. Figure 3-6 below shows the yearly average "all-in" wholesale electricity prices by region in New York State, indicating that prices in New York City and Long Island were higher than in the rest of the state (Eastern Upstate and Western New York)

Notably, relatively new transmission capacity into Long Island — from Connecticut, through the Cross Sound Cable, and from New Jersey through the Neptune cable — has provided some relief, as compared to New York City, in recent years.



Source: "2007 State of the Market Report," NYISO Independent Market Advisor, May 2008.

Figure 3-6: Average All-In Price by Sub-Region of New York – 2005 – 2007

Factors Posing Risks and Affording Resiliency Related to Fuel Diversity

The comparatively limited downstate fuel diversity poses certain risks for the New York City and Long Island areas. For obvious reasons, the wholesale prices in these areas are inextricably tied in the short run to price conditions in the natural gas market. Without changes in the transmission infrastructure allowing power from other fuel technologies to become available to the downstate regions, prices will continue to be shaped by relatively expensive fossil fuels in the downstate area.

As described previously, New York has evaluated the impact of an early shut-down of nuclear capacity at the Indian Point nuclear station north of New York City. The National Academy of Sciences Committee's assessment of the impacts of closing Indian Point concluded that natural-gas fired power plants were the most likely type of generating unit that could be added to replace the nuclear station. Thus, a closure could exacerbate New York City's existing dependence on natural gas for power production.

In spite of these challenges in the near term, there is promise and opportunity for New York to make its electric system more resilient. For example, the New York metropolitan port area has the ability to move energy products in and out of the locality; New York's off-shore wind and tidal resources could be developed, providing some indigenous sources of power; the state's significant municipal solid waste and demolition streams might provide gasified fuel for combustion in power plants.[9]

Finally, New York's state-owned power utility — New York Power Authority (NYPA) — has certain financial and legal capabilities that have enabled the agency to take actions that have met various evolving electricity needs over time in the state.[10]

Implications of New York's Fuel Diversity Profile

Like investment and development patterns in other parts of the U.S., those that have occurred in the electrical infrastructure in New York over the years are outcomes of countless decisions by public and private decision makers. The resulting fuel mix, then, reflects how policy makers and private entities have responded to the conditions, opportunities, and risks and reward structure confronting them.

The resulting blend of fuel mix, delivery structure, and use patterns in New York are given to various risks and/or unanticipated market outcomes, especially those associated with volatile fuel prices.[11]

Given the fact that the operation of New York's electrical system is heavily influenced by market forces and industry structure, this paper studies the options available to address fuel diversity and assesses the implications of taking the steps to achieve it. This paper also examines the variety of ways in which public policy makers and the market in New York has contributed to fuel diversity.

Section 4 of this paper focuses on the types of options that might be available (and in some cases, are being used elsewhere) to address fuel diversity issues in electrical systems. Where appropriate, the discussion will point out where a given approach has been used elsewhere and who might be the right entities to consider whether such an option might be appropriate to pursue. Presumably, since most of these options involve either a change in public policy and/or a change in market rules, the appropriate way to consider them is through stakeholder processes informed by more in-depth analysis of the trade-offs, and potential benefits and costs of adopting one or another strategy.

4. Fuel Diversity Options

In theory, there are many options available to address fuel diversity. Some are more or less intrusive into markets, some are nearer- or longer-term in nature, and some can be more or less well aligned with the structure of wholesale markets in New York. Some of the options focus on allowing greater diversity to withstand reliability effects of supply curtailments, but may address only moderating (if at all) the price impacts of doing so. Many involve trade-offs of one sort or another: Increasing downstate New York's access to some of the more diverse supplies in the upstate area may improve prices and reduce vulnerability of downstate consumers with either no benefits, perceived costs or actual transfers of impacts to the upstate region.

Historical Solutions in New York

Over the years, New York has directly undertaken a number of actions to ensure that New Yorkers have reliable supplies, in the face of potential fuel supply and/or delivery problems. While the list is too long to mention here, there have been a few notable examples in recent years.

For example, in order to address concerns about the impacts of a possible disruption in fuel supply in the New York City and Long Island areas (such as occurred after the 1989 gas line explosion affecting Consolidated Edison's Hellgate power plant), the New York State Reliability Council (NYSRC) has adopted "local reliability rules." They address operational requirements so that the system deals appropriately with "unique circumstances and complexities related to the maintenance of reliable transmission service, and the dire consequences that would result from failure to provide uninterrupted service."[12] Such operating standards, and cost-allocation requirements associated with them, are another way to mitigate the impacts of reliance on single critical fuels – and New York, through actions of the New York State Public Service Commission (NYSPSC) and the NYISO, has responded to the need to address them in the past.[13]

The NYISO has a number of market rules designed to address reliability concerns that might arise as a result of fuel dependency.[14] For example, in recent years steps have been taken to better align the timelines for submission and clearing of the NYISO's day-ahead energy and ancillary service markets, on the one hand, and the scheduling of natural gas into the Northeast, on the other. Similarly, various RTOs in the Northeast, including the NYISO, coordinate and share information about conditions on the natural gas system to help each other respond to abnormal events.

Less directly, but still important, the energy markets have responded to economic conditions in recent years in ways that have resulted in diversifying natural gas supplies and delivery systems into the Northeast. For example, natural gas pipeline companies continue to reinforce the delivery infrastructure into the Northeast in ways that support the resiliency of flows into the region. In the past two years, new pipeline delivery capacity totaling 1.7 billion cubic feet/day was added into the Northeast, with significant plans for further construction activity in upcoming years.[15] Additionally, the Northeast Gateway LNG project, located offshore of Gloucester, MA, went into commercial operation in 2007, along with the pipeline lateral to deliver gas into the Northeast natural gas pipeline system.

Also, while supplies of natural gas from conventional sources in North America have suffered declines in recent years, attention has turned to unconventional supply basins in many parts of North America.[16] One of the interesting prospects for development, for example, is the "Marcellus Shale" basin in the Appalachian region of West Virginia, Pennsylvania and New York — which is closer to Northeast gas demand locations than many other sources of unconventional gas supply. While there are challenges to developing this basin for production, there are indications of market interest, such as recent announcements by several interstate gas transmission companies of their plans to build connections to bring natural gas from the Marcellus Shale basin to the Northeast market.[17]

Together these many delivery and supply projects, along with the Maritimes and Northeast pipeline expansion that deliver gas from the Eastern Canadian provinces into the Northeast gas market, have helped to bolster the availability of supplies available to users in New York.

Short Term Options

In the near term, there is a limited set of options for modifying the fuel-mix profile of downstate New York or for mitigating the risk of price increases. Here are some of the options potentially available to address fuel diversity issues.

Enhance the ability to allow for fuel substitution

One option is adjusting the operating permit conditions for dual-fuel gas facilities located in downstate New York. As shown in Figure 3-3, much of Long Island's and New York City's power plant capacity is made up of units that can only burn natural gas. In the New York City area, the natural gas capacity is 23%, while it is 19% on Long Island. Much larger percentages of the generating fleets in those regions are capable of burning either gas or oil. Moreover, in the New York City area, gas-only power plants set the marginal clearing price in over 40% of the hours (as shown in Figure 3-5); on Long Island, they are on the margin 16% of the time.

Having the ability to switch between two different fuels adds greater operational flexibility for individual generators and for the system as a whole because facilities are less captive to price and/or supply/deliverability conditions in a particular fuel market. In principle, fuel substitution provides hedging against pricing power by suppliers of a fuel that would otherwise be essential to the reliability of the system.

After ISO-NE, for example, found itself in an electricity supply crunch when gas-only generating units sold off or lost their gas supplies during the cold snap of 2004, its grid operators, various market participants, and state energy and environmental officials focused attention on mitigating this risk in the future. After analysis, they adopted the following approaches: relicensing gas-only power plants located in New England so that they would also be capable of running on oil; expanding the size of on-site storage of oil at facilities; extending the number of hours of allowable operations on oil (under a facility's air permit) to enable it to be run during system emergencies called by the grid operator; and requiring power plant owners to retain gas supply for their own use in order to qualify for capacity credits. These actions led to a significant increase (an additional 2,270 MW) in the dual fuel capability of the New England fleet of generators.

In practice, to the extent that natural gas and oil prices are tightly correlated, in times when events in natural gas markets would prompt a desire to switch fuels, steps such as these may have minor benefits — in terms of both economics and reliability. Reliability is critically important in times when a failure to receive deliveries of gas supply into a region could threaten the electric system's ability to keep the lights on. But it may not do much to dampen the effects of fuel price volatility and price increases at those times.

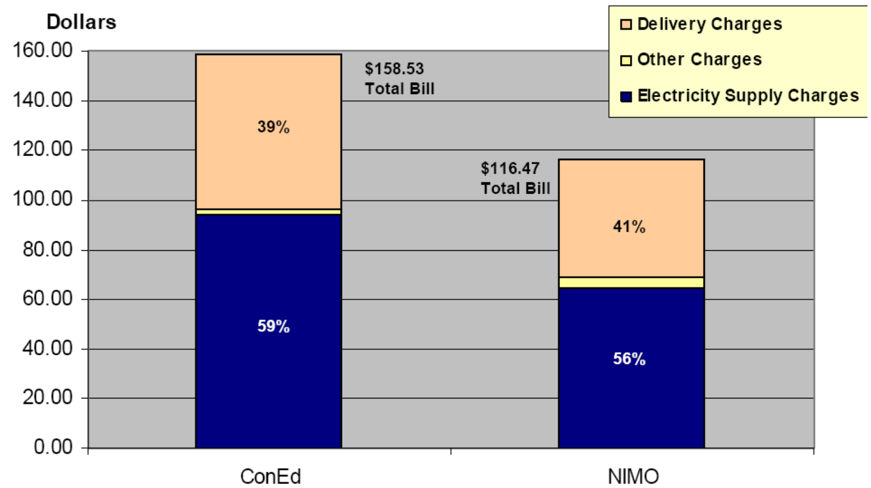
Energy efficiency, other demand-side measures and customer renewable energy

There is already renewed interest in New York in pursuing a variety of programs to induce greater efficiency in electricity use, greater response of demand to changes in supply and price conditions, and greater reliance on efficiency measures on the customer side of the meter.

For example, the Governor of New York State has established a "15x15" energy strategy aimed to achieve a reduction in statewide electricity usage by 15% by 2015. On June 23, 2008, the NYSPSC issued an order formalizing the Energy Efficiency Portfolio Standard (EEPS)[18]. The NYSPSC is requiring the state's investor-owned utilities to collect additional funds from electric and gas consumers to support the deployment of more energy efficiency measures than have been funded in recent years through the state's System Benefit Charge for programs implemented by the New York State Research and Development Administration (NYSERDA).[19] And the NYSPSC has adopted financial incentives to align the utilities' actions with the state's goal for adoption of much more aggressive energy efficiency programs than in the past. The new targets and funding sources are designed to "kick–start" the penetration and savings from efficiency programs.[20] Additionally, the Renewable Energy Task Force to then-Lieutenant Governor Paterson recommended that the state focus increasingly on a number of strategies to support "customer-side applications of solar photovoltaic (PV), solar thermal, sustainable biomass, anaerobic digesters, geothermal, small wind, small hydro (including kinetic power), and fuel cells."[21] Further, in the NYISO-administered demand-response programs, 2,125 MW of demand response capability has been enrolled.[22]

As noted in the documents establishing the value of energy efficiency and demand response programs to consumers in the state, customer-side measures are important in helping them mitigate the price impact of changes in fuel prices. The development of consumer-driven tools and programs makes it possible for consumers to make their own choices with respect to reducing energy use and/or obtaining energy from renewable sources on its own premises. The net result is that customers could have a direct role in mitigating the impact of fuel prices on their electricity bills.

For example, for a residential customer in New York City using 750 kWh per month, the average bill would have been $158.53 in January 2008.[23] (See Figure 4-1, which compares a Consolidated Edison (Con Edison) customer with a Niagara Mohawk customer.) For every kWh the Con Edison residential customer avoided consuming in January 2008 as a result of energy efficiency, the customer would have saved over 19½ cents (12.6 cents/kWh for supply; 6.8 cent/kWh for delivery charges; and 0.2 cents/kWh for other charges). (The comparable amounts for a Niagara Mohawk customer were 13.4 cents/kWh (total), with 8.6 cents/kWh for supply, 4.1 cents/kWh for delivery, and 0.6 cents/kWh for other.) Thus, saving 10% of a bill would have saved a New York City residential customer $15.85 per month (assuming 750 kWh original use and the rates in effect in January 2008). These savings are not insignificant for many households.



Source: New York Department of Public Service, http/www.dps.state.ny.us/typical_bills/util_elec_res_bills_Jan_2008.pdf

Figure 4-1: Total Residential Customer Bill – Con Edison and Niagara Mohawk
(@750 kWh/month – January 2008)

That said, the adoption of these programs may not greatly affect the actual prices New York faces in its electric energy markets, at least without seeing energy efficiency, demand response and customer-side renewable applications greatly reduce demand in a large number of hours of the year. Since gas or dual-fuel oil/gas capacity is the marginal fuel in almost 90% of the hours of the year in the New York City area, then the addition of demand-side resources are unlikely to have a significant effect on de-linking electricity clearing prices from natural gas, even though such resources may provide value to consumers in the form of lower electricity bills (from lower power use). Unless demand-side measures dig quite deeply into the load curve in periods when the marginal fuel can shift away from gas, this particular approach does not particularly address fuel diversity issues *per se*.

Bring non-gas resources into downstate New York –strategies to expand transfer capacity from north to south

The principal factor that splits New York State into two separate upstate and downstate electrical areas is the limitation on the ability of the high-voltage transmission system to transfer power produced upstate to loads in the downstate (New York City and

Long Island) areas. Currently, the transmission system is rated higher than its actual ability to move power to Load Zones I-K (New York City metropolitan area and Long Island), due to a variety of reliability constraints that require the NYISO to operate the system below its full capability. Were these operating limitations able to be modified so that more low-cost power supplies could be dispatched in upstate New York for downstate customer requirements, then the NYISO would be able to forego dispatching some of the more expensive power generators located in downstate zones. In turn, this would have the potential to reduce locational marginal prices for electrical energy downstate, as the NYISO could avoid dispatching less efficient generators with higher energy bid prices.

The NYISO has analyzed the cost and benefits of having various hardware measures, such as capacitor banks in key locations, installed by market participants so as to enable the grid operator to move more power over the north-to-south transmission grid. According to a recent NYISO study, an investment of $80 million in capacitor banks could increase power flows and lower line losses, amounting to approximately $60 million per year in wholesale energy savings for the state's system as a whole. Measures like this have the ability to moderate the downstate region's lack of fuel diversity and its exposure to high and volatile natural gas prices.

Enhance hedging strategies and practices

Since one of the principal consequences of downstate New York's dependence on natural gas is the risk of fuel price volatility and price increases, one way to mitigate the impact of this lack of fuel diversity is to ensure that there is an efficient and optimal amount of hedging being carried out by electricity providers.

New York is a state with retail choice; so, many customers and competitive retail suppliers are making their own arrangements for commodity supply and pricing. This is reflected in the fact that, as of December 2007, almost nine out of ten large customer accounts (and 95% of their load) on Con Edison's time-of-use rates had "migrated" away from basic service provided by Con Edison, with 20% of medium commercial and industrial customers having migrated (with 47.5% of their load).[24] By contrast, just under 15% of residential customers and loads had migrated away to competitive retail suppliers.[25] This means that Con Edison was in the position of arranging and providing electricity for about five out of every six residential customers, and about four out of five medium-sized non-residential customers. As such, Con Edison — like other investor-owned utilities with responsibility to arrange commodity supply for its non-migrating customers — is responsible for any and all hedging activities, subject to oversight from the NYSPSC.

In 2007, the NYSPSC issued an order[26] (the "Supply Portfolio Order") which found that most mass market customers generally find beneficial the restraints on electric commodity price volatility that utilities are able to achieve, because those customers are generally risk-averse. The NYSPSC's Supply Portfolio Order therefore required utilities to set standards for measuring volatility, and to set goals for constraining price volatility "to levels that are acceptable." The NYSPSC decided "that electric utilities should engage in hedging practices intended to reduce the volatility of the commodity prices they charge customers electing to take commodity supply from them instead of from alternative providers. The Supply Portfolio Order also requires electric utilities to participate in collaborative discussions for the purpose of developing electric price volatility metrics; establish goals for reducing volatility as measured by those metrics; and recommend requirements for reporting electric utility supply price information."[27]

In this and prior orders, the NYSPSC actively involved stakeholders in commenting on the question of the extent to which utilities should undertake hedging strategies on a voluntary or mandatory basis. As recently as December 2007, the NYSPSC determined that it would continue to "encourage the use of voluntary forward contracts of all durations by all parties, together with all other instruments legitimately used in any competitive market. If the wholesale markets have a reasonable balance of spot purchases together with short-, medium-, and long-term contracts, retail price volatility and the opportunities to exercise market power at the wholesale level could be reduced, as could the investment risks of both new and existing generation."[28]

New York is continuing to examine the appropriateness of the role of hedging in commodity supply to basic service customers in the state, as one of the important ways in which electricity providers can address and mitigate the impacts of fuel dependence in the state.

Emergency actions

There are examples in other regions where disruptions in fuel supply or delivery or unexpected outages of power plants critical to system reliability have led to an array of emergency actions being taken by public officials, utilities and grid operators. During such events in recent years the grid operator and other players took steps to heighten large and small customers' awareness of reliability challenges and to encourage voluntary and aggressive energy conservation. Additionally, steps were taken to move into the region mobile generators and other emergency equipment to assure that the lights would stay on.

The industry has a long and effective history of instituting procedures outlining actions to take in the event of a capacity or energy emergency. These steps involve long-standing agreements among utilities to assist each other in restoring service and other forms of aid in the event of emergencies. Such actions were widespread, for example, when utility crews from all around the East Coast traveled to the Gulf Coast areas to assist in restoring power and other energy services in the wake of Hurricanes Katrina and Rita, and after Hurricane Ike hit parts of Texas in 2008. The outages caused by the effects of these natural disasters were massive and lengthy. Moreover, the nation's dependence on natural gas and oil supplies emanating from the Gulf States did have impacts on various energy markets affected by price increases caused by lack of production in the aftermath of the hurricanes.

There are examples in the industry of how a system has responded in the face of extraordinary electricity supply shortages and price increases. The actions taken during the "California electricity crisis," over the period from the summer of 2000 through late 2001, are examples of what grid operators, utilities and state officials can do on an emergency basis to address rising prices and looming power shortages over some sustained period of time. Starting in the spring of 2000, the California ISO (CAISO) instituted its "Power Alert" program, with a series of mechanisms to provide cues to the public about the real-time operating conditions of the grid. Over the course of the next year and a half, as a "perfect storm" of conditions collided to raise prices and tighten electricity supplies, CAISO, the utilities, the state and others adopted measures that included: instituting new siting procedures to expedite the consideration and approvals of new power plant projects; implementing aggressive energy efficiency programs; issuing urgent appeals for conservation; and redesigning the retail price of electricity so that customers would pay dramatically higher marginal prices if their usage levels were above some "basic service" threshold established by the public utility commission. The point of this brief discussion is primarily to highlight the role crises play in shaping market rules and policies.

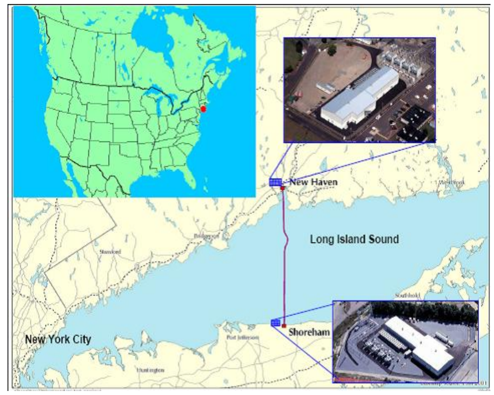
One thing to note when considering how emergency responses could be deployed in the event of a crisis: A fundamental plank of most emergency programs to deal with capacity or energy shortages, or periods of volatile or high prices, is to issue calls to the public for voluntary conservation. As the region proceeds to implement more and more energy efficiency over time and becomes more reliant on a routine and systematic basis on demand-side strategies (e.g., price-responsive demand and demand-response programs, whether run by the NYISO or others), it will be important for grid operators, utilities and the government to gauge how much incremental reduction in load can be counted on in an emergency.

Longer Term Options

Some of the strategies described above — energy efficiency and demand-side measures, hedging approaches, and fuel-substitution measures — are also applicable to the longer term as well. But an additional set of tools may present themselves for consideration if the time line is many years into the future.

Incentives for investment in transmission into downstate New York

As described above, one principal way to diversify the fuel mix of the New York City and Long Island areas would be to enhance the capacity of the transmission system to move in power from other areas. Two examples of recent steps taken by merchant transmission developers to do just that are the Cross Sound Cable, connecting Long Island to Connecticut which entered service in 2003, and the Neptune Cable, connecting Long Island to New Jersey, which entered service in 2007. (Interestingly, disputes over environmental impacts of the Cross Sound Cable kept it from going into operation upon completion of construction; it was only after reliability concerns following the Northeast Blackout of 2003 that the facility was allowed to enter into operation.[29]) The locations of the Neptune Cable and the Cross Sound Cable are shown below in Figures 4-2 and 4-3.



Source : http ://www.neptunerts.com/, http ://www.crosssoundcable.com/CableInfonew.html, http://www.lipower.org/company/powering/neptune.html

Figure 4-2: Neptune Cable
Sayerville, NJ to Newbridge, NY

Figure 4-3: Cross Sound Cable
Shoreham, NY to New Haven, CT

The NYISO has an active planning process to examine reliability and economic upgrades to the transmission system. The most recent addition to the NYISO's Comprehensive Reliability Planning Process (CRP Process) is the Congestion Assessment and Resource Integration Study (CARIS) process to examine the benefits and costs to the system of economic upgrades to the transmission system. Given the market rules and industry structure in the state's electric system, there is a strong preference for looking for market-based means to add transmission (or generation or demand-side solutions), with the NYISO providing information to market participants about the trade-offs (in terms of congestion impacts, reliability improvements, production cost savings, and other impacts) associated with transmission capacity additions in various locations on the grid.

Additionally, New York State has begun a new round of state-wide energy planning that will certainly inform decisions in the future by potential investors in electric infrastructure, including NYPA.

One of the approaches being used in New York to diversity its fuel mix (and address economic and environmental issues at the same time) is to facilitate the development of wind resources located in the state. Figure 4-4 shows the existing and proposed wind projects in New York State by county.

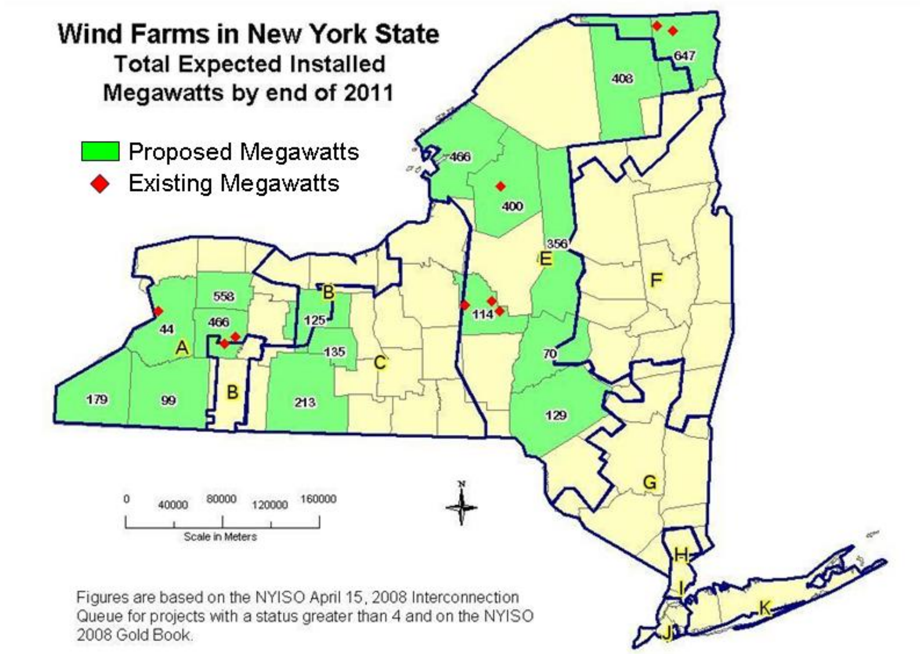


Figure 4-4: Wind Farms in New York State

New York is third among the states in wind capacity under construction. As of June 30, 2008, only Texas and Iowa had more wind capacity under construction.[30] At that time, New York State had 706.8 MW of wind power, with 588.5 MW more under construction. And, as shown in Figure 4-4, above, thousands more MWs of wind capacity have been proposed in the state.

Wind projects support fuel diversity in New York's power market, since most other new generating capacity added in the past decade and currently proposed is from power plants that use natural gas – a fossil fuel whose price has tripled since 2000. The price of wind remains the same over the same period: zero cents per kWh.

As indicated in Figure 4-4, most of the wind developments are in the upstate area. Therefore, without enhancements to the transmission grid in the state that will allow greater transfers of power from north to south, the wind resources may do little to reduce energy prices and diversify the downstate mix. Moreover, without transmission enhancements enabling greater delivery of wind, wind turbines may be required to dispatch down even when the wind is blowing because the grid would otherwise become overloaded with too much power for the local region to absorb.[31]

Like New York, other regions are actively engaged in analyzing the interactions between transmission expansion plans and the development of renewable resources and exploring ways to enhance incentives for transmission investment for moving renewable power. One example is the "Joint Coordinated System Plan," being prepared by various regional transmission organizations and other transmission providers in the Eastern Interconnection: NYISO, PJM, ISO-NE, MAPP, MISO, and TVA. This long-term, interregional planning initiative is examining the implications for transmission of a nationwide 20-percent renewables mandate by 2024.[32]

Among the various issues that must be addressed is how best to analyze benefits and costs of "strategic" investments in transmission, designed for strategic purposes such as supporting wind development for fuel diversity, environmental and energy security reasons. A recent analysis[33] by Lawrence Berkeley National Laboratory (LBNL)[34] for California's Public Interest Energy Research (PIER) program observed that our tools for analyzing strategic transmission investments may need to evolve in order to capture fully the benefits of facilities providing not only the traditional transmission system functionalities (e.g., helping to meet reliability standards, lowering costs of congestion and losses, enabling inter-regional trading), but also indirect strategic benefits and "insurance" benefits (including such things as renewable resource development and integration, fuel diversity, emissions reduction, market power mitigation, insurance against contingencies, hedging against market volatility, and insurance against extreme event impacts). The study encourages broadening the array of variables examined to include certain impacts beyond those internalized in electricity markets alone.[35]

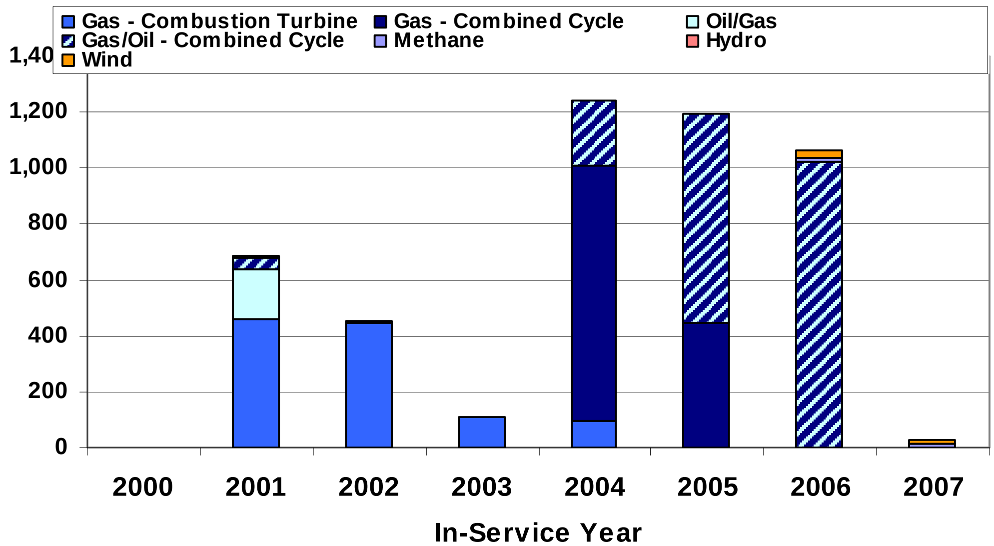
Other incentives for investment in non-gas-fired power generation facilities

The work underway in New York to stimulate further development of wind resources (described briefly above) is aimed, among other things, at diversifying the fuel mix in the state. The wind capacity additions are notable for the fact that they are different than the typical generating capacity additions built in New York in recent years. Since the NYISO opened its markets in 1999, much generating capacity has been added, but as shown in Figure 4-5, most of it has been gas-fired generating capacity. While generation has been successfully located in relatively close proximity to load (in part in response to signals from the market design in New York), it has nonetheless been the case that virtually all new generating capacity (besides recent wind projects) consists of plants that burn natural gas.

Were New York to decide that it valued other types of generating resources besides natural gas (and wind), state policy could be adjusted accordingly. These adjustments might include:

- Establishing a "fuel diversity portfolio standard"
- Implementing measures (such as special purpose zones) to facilitate the siting of facilities other than natural gas
- Assisting with long-term contracting for capital-intensive facilities

Some of these, such as the latter, are indirectly the subject of the New York NYSPSC's Supply Portfolio Order, discussed previously. Others are the object of continued stakeholder appeals (e.g., the need for New York to reinstate its Article X power plant siting process). That said, many observers note that even were such policies to be adopted by the state, it may remain difficult — if not impossible — politically to site and construct any conventional central-station power plants in the downstate area that use any fuel besides natural gas.



Data include capacity additions through March 2008. Source: NYISO Generator List, 2008[2]

Figure 4-5: Power Plant Capacity Added in New York (since 1999)
(MW – summer capacity)

The "energy zone" concept is what has been used to support the development of energy resources that are bound to a particular location (such as wind), and which benefit from particular planning studies designed to focus on impediments to resource development. In theory, this latter concept could be used to analyze the potential for development of other types of electric generating facilities — such as those that might use as their fuel a portion of the municipal waste streams and demolition debris (to be gasified, for example, rather than incinerated) from locations in urbanized areas of downstate New York. These other "fuel zones" might be a way to organize analyses and focus attention on issues that need to be addressed to stimulate the development of additional, non-natural-gas-fired facilities in the downstate area.

The "fuel diversity standard" is a notion borrowed directly from the conceptual underpinnings of the state's "Renewable Portfolio Standard" (RPS). New York, like almost half of the states in the U.S.,[3 36] has an RPS — a state policy requirement that electricity providers obtain a certain percentage of their power from eligible renewable resources. New York's RPS allows support for the following eligible renewable and other resources: photovoltaics (solar), landfill gas, wind, biomass, hydroelectric, fuel cells, anaerobic digestion, tidal energy, wave energy, ocean thermal, ethanol, methanol,

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[2] Available at www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2008_NYCA_Generators.xls

[3] Currently there are 24 states plus the District of Columbia that have RPS policies in place. These represent more than half of the electricity sales in the United States.

and biodiesel.[37] This policy is a market-based mechanism to support demand for renewable power. Renewable attributes of power produced by such projects become a commodity capable of being unbundled from the "regular" electric energy and capacity related products associated with a particular plant. The producer of energy from qualifying facilities creates a "renewable energy credit" for every unit of electric energy produced by the facility. The facility can fully and efficiently participate in "regular" ISO-administered energy markets, and when dispatched can produce renewable energy credits, which can be bought and sold together with or separately from the underlying power production itself. This would provide an incremental revenue stream to support investment in and operation of the facility.

While this approach has been primarily for renewable resource procurement and development, there are some examples where it has been used for other energy resources as well. Pennsylvania, for example, has an "Alternative Energy Portfolio Standard," for which not only renewables but also other resources such as municipal solid waste, cogeneration, waste coal, coal mine methane, coal gasification, anaerobic digestion, and other distributed generation technologies are eligible.[38]

If a state determined that it was in the public interest to support development of a particular type of electric resource (besides renewables) that was not otherwise coming forth from the decisions of private investors in the power market, the "portfolio standard" might be an approach to use to encourage development. This could be more compatible with the market designs that exist in New York's wholesale and retail electricity markets. As described in a prior white paper (by Tierney) prepared for the NYISO:

> "In theory, this approach could be applicable to other types of attributes that are currently undervalued in current markets (e.g., fuel diversity). Demand for the attribute of interest could be created through state-imposed content-requirement mandates (such as those established for renewable attributes by Renewable Portfolio Standards), or through other means (e.g., through the centralized purchase of attribute credits by a centralized entity with funding provided to do so). Continuing the analogy to renewable energy credit markets, some states impose the requirement on all load-serving entities to procure through decentralized markets the requisite amount of attribute credits; in other states, a central purchasing agent issues requests-for-proposals for attribute credits, that are paid for by a source of funding available to the centralized purchasing agent (i.e., New York State Energy Research and Development Authority in New York State). Suppliers of the attribute are still expected to participate in the region's regular energy markets, as all other producers of power are required to do.[39]"

Incentives for investment in fuel deliverability and storage

Similarly, the state may want to put in place incentives for improving the reliability of fuel delivery and storage. If one of the problems experienced in regions dependent on particular fuels is that they fall prey to economic, technical or strategic disruptions in the fuel distribution networks, then one way to mitigate this impact is to reinforce the strength of the delivery systems themselves. This reinforcement can come in the form of creating incentives for stronger commitments between the buyer of the fuel and its transporter. For example, New England does not permit generators that seek to qualify for payments in the capacity market to take an "economic outage" in that same capacity period. (An economic outage is one where a generator requests to be allowed to be out of service for purely economic reasons associated with fuel market conditions.)

There are other ways to shore up supplies and transportation of fuels. Some states require a demonstration by certain regulated energy entities (typically gas distribution utilities) that they have firm transportation and storage arrangements for fuel delivery during the winter heating season at a sufficient level to meet requirements during "design winter" conditions. In theory, state policy could address delivery arrangements for other types of energy entities if the state considered this a matter of high public interest and worth the costs that would be imposed on consumers through the markets for power and other energy resources.

Additionally, a state could support and/or facilitate the siting and development of other local fuel delivery or storage infrastructure, such as natural gas pipelines, satellite or centralized storage facilities for LNG or petroleum, and centralized terminals for gasification and liquefaction of LNG. While there are potential issues of federal/state jurisdiction over the siting of some of these facilities, it is nonetheless possible for a state to decide it wanted to support the development of such local infrastructure in particular locales or sites, if it determined that there was a compelling state interest in doing so. (Note here again that in recent years, several new interstate natural gas infrastructure projects have been completed in New York State and neighboring regions that support the interstate pipeline system's deliveries into New York State.[4],[40])

Policy information and advocacy

There are several additional options through which New York could assist in addressing fuel diversity. One would be to take an active position on national policies affecting energy resource availability or cost to the state.

For example, when discussions begin to become more active in Washington, D.C. with regard to the shape of the national carbon-control program, an important issue that will affect the comparative impacts on New York State energy consumers will be the design of the greenhouse gas emissions allowances program. New York State has already stepped into the policy arena on greenhouse gases through its participation in the Regional Greenhouse Gas Initiative (RGGI) which will require certain generators in New York and other states in the Northeast to begin to control their emissions of carbon. For example, the ways in which the national program might intersect and interact with RGGI (e.g., through the possibility of federal preemption, through overlays of state and federal programs), and allocate allowances to generators based on historical emissions of carbon, will directly impact New York's electric industry participants (especially consumers.) But the national policy will likely also have indirect impacts as well, given the potential impact on electricity prices in neighboring states.

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[4] Among the natural gas pipeline projects listed as completed in 2007 by the EIA are: Tenneco's Northeast ConneXion compression project, and Transco's Leidy-to-Long Island Expansion project.

Another option for policy advocacy, adoption and implementation would be to support particular directions in energy research — either directly, through the NYSERDA research program, or more indirectly, through cooperation and advocacy before other energy research and development organizations. This could include the U.S. Department of Energy, its national laboratories (one of which, Brookhaven, is located within New York State), the Electric Power Research Institute, and other research and development forums. There are important options that may affect New York's interests in fuel and technology diversity that may be advanced by the direction of research programs in the future.

Another option for New York's future fuel and technology diversity path is to support the development of certain "game-changing" or disruptive technologies. Prime examples are plug-in hybrid electric vehicles (PHEV). They not only plug into the grid to draw power to fuel a battery, but also are capable of reversing the flow of power from the vehicle to the grid, so that the vehicle becomes a micro distributed generator. This is a technology about which much has been written in recent years, but which still will require substantial analysis and information to explore the manner in which such vehicles integrate with the power system.[41],[42]

Finally, there are myriad ways in which the evolution of a "smart grid" system in New York State might affect the impacts on consumers of the state's dependency of single fuels. This is a topic of enormous breadth, with possible implications ranging from enabling customers to better manage their own electricity use in the face of price signals and other information from the market, to integration of new technologies (such as PHEV) with the potential to reshape the nature of electricity demand, storage, delivery and supply in untold ways.

5. Conclusion

While there is no industry standard for determining what exactly constitutes “fuel diversity” in comparison to most states the electric supply fuel mix in New York State can be called diverse. The New York electric utility system relies on supply from numerous fuel sources, including water, wind, nuclear and natural gas, as well as interconnections with its neighbors and demand-response resources to meet the needs of the 19 million residents in the state.

The New York fuel diversity picture changes when viewed from an upstate vs. downstate perspective. In this context the diversity of the upstate region is much greater than that of the downstate region where except for the Indian Point nuclear plant the fuel mix is dominated by natural gas and dual fuel (gas and oil) powered generators. This relative lack of downstate diversity is partially mitigated by transmission connecting the downstate region to the more diverse upstate region of New York. The ability of the existing transmission system to transfer power from north to south has limits, and the continued growth in downstate demand for electricity will mainly rely on natural gas and oil fueled local resources until the transmission system is expanded or unless the right incentives are in place attract alternate resources. These local solutions could include more demand response, energy efficiency, new technologies that can optimize the existing transmission infrastructure and alternate fuel sources such as renewable energy and LNG.

Maintaining and improving fuel diversity in New York will likely to lead to less volatile electric prices, improved reliability and positive environmental impacts. It is essential that public policy makers and the NYISO confront the risks that are posed by inadequate fuel diversity. Market forces should be harnessed and planning principles should be utilized to encourage signals that will lead to support for the protocols and technologies necessary to move New York towards an optimum fuel diversity profile.

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Utility-Scale Solar 2014

An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States

Authors: Mark Bolinger and Joachim Seel

Lawrence Berkeley National Laboratory

September 2015

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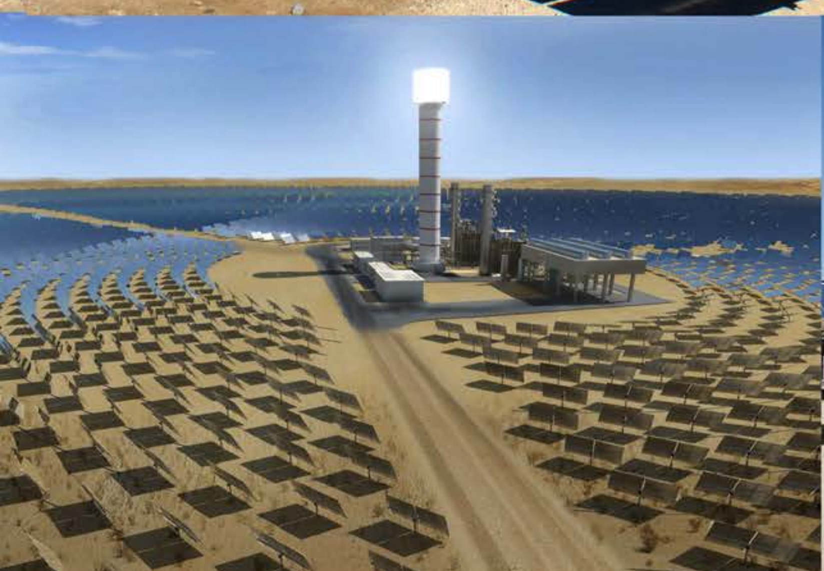

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Authors: Mark Bolinger and Joachim Seel
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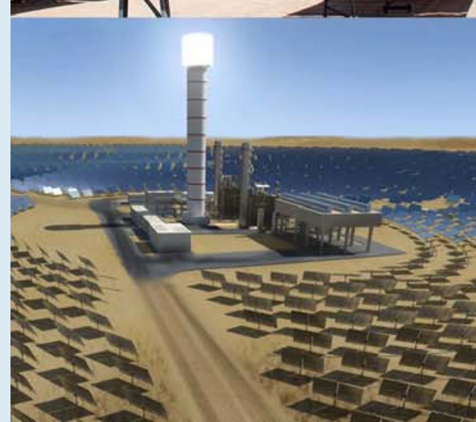

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List of Acronyms

AC	Alternating Current
c-Si	Crystalline Silicon
COD	Commercial Operation Date
CPV	Concentrated Photovoltaics
CSP	Concentrated Solar (Thermal) Power
DC	Direct Current
DIF	Diffuse Horizontal Irradiance
DNI	Direct Normal Irradiance
DOE	U.S. Department of Energy
EIA	Energy Information Agency
EPC	Engineering, Procurement & Construction
FERC	Federal Energy Regulatory Commission
GHI	Global Horizontal Irradiance
FiT	Feed-in Tariff
ILR	Inverter Loading Ratio
ISO	Independent System Operator
ITC	Investment Tax Credit
LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized Cost of Energy
MW	Megawatt(s)
NCF	Net Capacity Factor
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
PII	Permitting, Interconnection & Inspection
PPA	Power Purchase Agreement
PV	Photovoltaics
REC	Renewable Energy Credit
RTO	Regional Transmission Organization
SEGS	Solar Energy Generation Systems
TOD	Time-Of-Delivery

Executive Summary

Other than the nine Solar Energy Generation Systems ("SEGS") parabolic trough projects built in the 1980s, virtually no large-scale or "utility-scale" solar projects – defined here to include any ground-mounted photovoltaic ("PV"), concentrating photovoltaic ("CPV"), or concentrating solar thermal power ("CSP") project larger than 5 MW_{AC} – existed in the United States prior to 2007. By 2012 – just five years later – utility-scale had become the largest sector of the overall PV market in the United States, a distinction that was repeated in both 2013 and 2014 and that is expected to continue for at least the next few years. Over this same short period, CSP also experienced a bit of a renaissance in the United States, with a number of large new parabolic trough and power tower systems – some including thermal storage – achieving commercial operation.

With this critical mass of new utility-scale projects now online and in some cases having operated for a number of years (generating not only electricity, but also empirical data that can be mined), the rapidly growing utility-scale sector is ripe for analysis. This report, the third edition in an ongoing annual series, meets this need through in-depth, annually updated, data-driven analysis of not just installed project costs or prices – i.e., the traditional realm of solar economics analyses – but also operating costs, capacity factors, and power purchase agreement ("PPA") prices from a large sample of utility-scale solar projects in the United States. Given its current dominance in the market, utility-scale PV also dominates much of this report, though data from CPV and CSP projects are presented where appropriate.

Some of the more-notable findings from this year's edition include the following:

- ***Installation Trends:*** Among the total population of utility-scale PV projects from which data samples are drawn, several trends are worth noting due to their influence on (or perhaps reflection of) the cost, performance, and price data analyzed later. For example, the use of tracking devices (overwhelmingly single-axis, though a few dual-axis tracking projects entered the population in 2014) continues to expand, particularly among thin-film (CdTe) projects, which had almost exclusively opted for fixed-tilt mounts prior to 2014. The quality of the solar resource in which PV projects are being built in the United States has increased on average over time, as most of the projects in the population (>90% in MW terms) are located in the Southwest where the solar resource is the strongest. That said, the market has also begun to expand outside of the Southwest, most notably in the Southeast. The average inverter loading ratio – i.e., the ratio of a project's DC module array nameplate rating to its AC inverter nameplate rating – has also increased among more recent project vintages, as oversizing the array can boost revenue, particularly when time-of-delivery pricing is used. In combination, these trends should drive AC capacity factors higher among more recently built PV projects (a hypothesis confirmed by the capacity factor data analyzed in Chapter 5). Finally, 2014 also saw three new large CSP projects – i.e., two 250 MW trough projects and one 377 MW solar power tower project – achieve commercial operation; in contrast, no new CPV plants came online in 2014.

- ***Installed Prices:*** Median installed PV project prices within a sizable sample have steadily fallen by more than 50% since the 2007-2009 period, from around $\$6.3/W_{AC}$ to $\$3.1/W_{AC}$ (or $\$5.7/W_{DC}$ to $\$2.3/W_{DC}$, all in 2014 dollars) for projects completed in 2014. The lowest-priced projects among our 2014 sample of 55 PV projects were ~$\$2/W_{AC}$, with the lowest 20th percentile of projects having fallen considerably from $\$3.2/W_{AC}$ in 2013 to $\$2.3/W_{AC}$ in 2014.

The three large CSP projects that came online in 2014 were priced considerably higher than our PV sample, ranging from $5.1/W_{AC}$ to $6.2/W_{AC}$.

- ***Operation and Maintenance ("O&M") Costs:*** What limited empirical O&M cost data are publicly available suggest that PV O&M costs appear to have been in the neighborhood of $20/kW_{AC}$-year, or $10/MWh, in 2014. CSP O&M costs are higher, at around $40-$50/kW_{AC}$-year. These numbers include only those costs incurred to directly operate and maintain the generating plant, and should not be confused with total operating expenses, which would also include property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead.

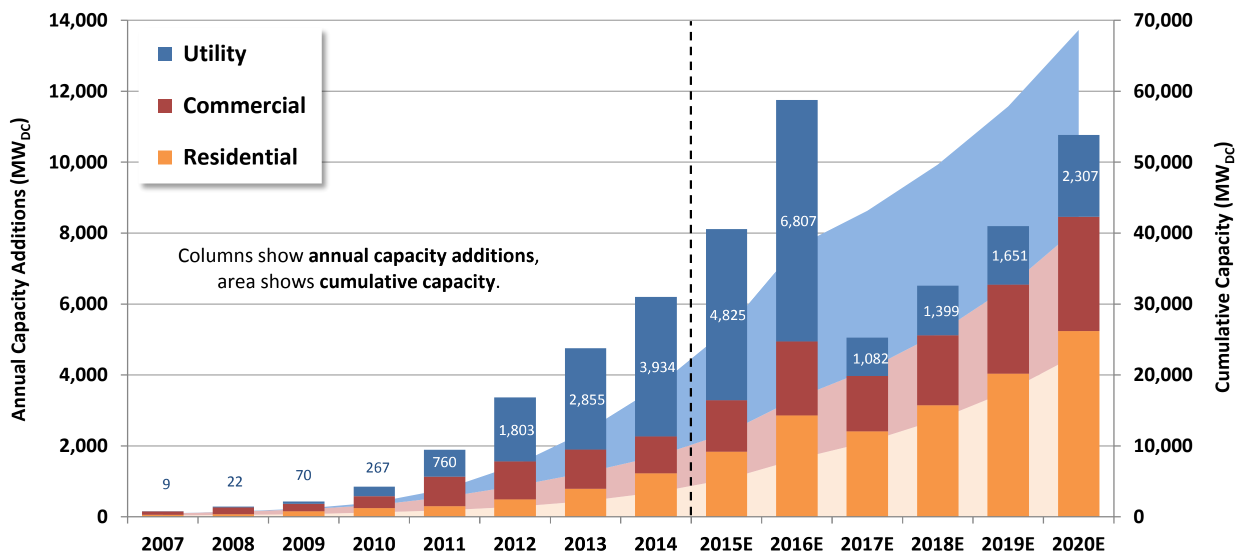
- ***Capacity Factors:*** The capacity-weighted average cumulative capacity factor across the entire PV project sample is 27.5% (median = 26.5% and simple average = 25.6%), but individual project-level capacity factors exhibit a wide range (from 14.8% to 34.9%) around these central numbers. This variation is based on a number of factors, including (in approximate decreasing order of importance): the strength of the solar resource at the project site; whether the array is mounted at a fixed tilt or on a tracking mechanism; the inverter loading ratio; and the type of modules used (e.g., c-Si versus thin film). Improvements in the first three of these factors have driven capacity-weighted average capacity factors higher by project vintage over the last three years – e.g., 29.4% among 2013-vintage projects, compared to 26.3% and 24.5% for projects built in 2012 and 2011, respectively. In contrast, two of the new CSP projects built in recent years – a trough project with storage and a power tower project – generated lower-than-expected capacity factors in 2014, reportedly due to startup and teething issues. Performance has subsequently improved at both projects during the first six months of 2015 (compared to the same period in 2014). Likewise, the two CPV projects in our sample seem to be underperforming, relative to both similarly situated PV projects and ex-ante expectations.

- ***PPA Prices:*** Driven by lower installed project prices, improving capacity factors, and – more recently – the rush to build projects in advance of the scheduled reversion of the 30% investment tax credit ("ITC") to 10% in 2017, levelized PPA prices for utility-scale PV have fallen dramatically over time, by a steady ~$25/MWh per year on average from 2006 through 2013, with a smaller price decline of ~$10/MWh evident in the 2014 and 2015 samples. Some of the most-recent PPAs in the Southwest have levelized PPA prices as low as (or even lower than) $40/MWh (in real 2014 dollars). At these low levels – which appear to be robust, given the strong response to recent utility solicitations – PV compares favorably to just the fuel costs (i.e., ignoring fixed capital costs) of natural gas-fired generation, and can therefore potentially serve as a "fuel saver" alongside *existing* gas-fired generation (and can also provide a hedge against possible future increases in fuel prices).

Looking ahead, the amount of utility-scale solar capacity in the development pipeline suggests continued momentum and a significant expansion of the industry through at least 2016. For example, at the end of 2014, there was at least 44.6 GW of utility-scale solar power capacity making its way through interconnection queues across the nation (though concentrated in California and the Southwest). Though not all of these projects will ultimately be built, presumably those that are built will most likely come online prior to 2017, given the scheduled reversion of the 30% ITC to 10% at the end of 2016. Even if only a modest fraction of the solar capacity in these queues meets that deadline, it will still mean an unprecedented amount of new construction in 2015 and 2016 – as well as a substantial amount of new data to collect and analyze in future editions of this report.

1. Introduction

The term "utility-scale solar" refers both to large-scale concentrating solar power ("CSP") projects that use several different technologies to produce steam used to generate electricity for sale to utilities,[1] and to large photovoltaic ("PV") and concentrating photovoltaic ("CPV") projects that typically sell wholesale electricity directly to utilities, rather than displacing onsite consumption (as has been the more-traditional application for PV in the commercial and residential markets). Although utility-scale CSP has a longer history than utility-scale PV (or CPV),[2] and has recently experienced a bit of a renaissance,[3] the utility-scale solar market in the United States is now largely dominated by PV: there is currently significantly more PV than CSP capacity either operating (6.4x), under construction (30.5x), or under development (12.1x) in utility-scale projects (SEIA 2015). PV's dominance follows explosive growth in recent years: utility-scale PV has been the fastest-growing sector of the PV market since 2007, and since 2012 has accounted for the largest share of the overall PV market in terms of new MW installed (with 3,934 MW_{DC} of new capacity added in 2014 alone – see Figure 1), a distinction that is projected to continue through 2016 (GTM Research and SEIA 2015).[4]



Source: GTM/SEIA (2010-2015), Tracking the Sun Database

Figure 1. Historical and Projected PV Capacity by Sector in the United States

[1] Operating CSP projects most commonly use either parabolic trough or, more recently, power tower technology. CSP projects using other technologies, including compact linear Fresnel lenses and Stirling dish engines, have also been built in the United States, but largely on a pre-commercial prototype basis.
[2] Nine large parabolic trough projects totaling nearly 400 MW_{AC} have been operating in California since the late 1980s/early 1990s, whereas it was not until 2007 that the United States saw its first PV project in excess of 5 MW_{AC}.
[3] More than twice as much CSP capacity came online in the United States in 2013/2014 as in the previous 28 years.
[4] GTM/SEIA's definition of "utility-scale" reflected in Figure 1 is not entirely consistent with how it is defined in this report (see the text box – *Defining "Utility-Scale"* – in this chapter for a discussion of different definitions of "utility-scale"). In addition, the capacity data in Figure 1 are expressed in DC terms, which is not consistent with the AC capacity terms used throughout the rest of this report (the text box – *AC vs. DC* – at the start of Chapter 2 discusses why AC capacity ratings make more sense than DC for utility-scale projects). Despite these two inconsistencies, the data are nevertheless useful for the basic purpose of providing a general sense for the size of the utility-scale market (both historical and projected) and demonstrating relative trends between market segments.

This rapidly growing utility-scale sector of the solar market is ripe for analysis. Historically, empirical analyses of solar economics have focused primarily on up-front installed costs or prices, and principally within the residential and commercial PV sectors (see, for example, Barbose and Darghouth 2015). But as more utility-scale projects have come online and begun to acquire an operating history, a wealth of other empirical data has begun to accumulate as well. Utility-scale solar projects can be mined for data on not only installed prices, but also project performance (i.e., capacity factor), operation and maintenance ("O&M") costs, and power purchase agreement ("PPA") prices ($/MWh) – all data that are often unavailable publicly, and are also somewhat less meaningful,[5] within the residential and commercial sectors.

This report is the third edition in an ongoing annual series that, each year, compiles and analyzes the latest empirical data from the growing fleet of utility-scale solar projects in the United States. In this third edition, we maintain our definition of "utility-scale" to include any ground-mounted project with a capacity rating larger than 5 MW_{AC} (the text box below describes the challenge of defining "utility-scale" and provides justification for the definition used in this report). Within this subset of solar projects, the relative emphasis on different solar technologies within the report largely reflects the distribution of those technologies in the broader market – i.e., most of the data and analysis naturally focuses on PV given its large market share (78% of cumulative installed capacity), but CPV (<1%) and CSP (21%) projects are also included where useful data are available.

The report proceeds as follows. First, Chapter 2 describes key characteristics of the overall utility-scale solar project population from which the data samples that are analyzed in later chapters are drawn, with a goal of identifying underlying technology trends that could potentially influence trends in the data analyzed in later chapters. The remainder of the report analyzes the cost, performance, and price data samples in a logical order: up-front installed costs or prices are presented in Chapter 3, followed by ongoing operating costs and performance (i.e., capacity factor) in Chapters 4 and 5, all of which influence the PPA prices that are reported and analyzed in Chapter 6. Chapter 7 concludes with a brief look ahead.

Data sources are diverse and vary by chapter depending on the type of data being presented, but in general include the Federal Energy Regulatory Commission ("FERC"), the Energy Information Administration ("EIA"), state and federal incentive programs, state and federal

[5] For example, even if performance data for residential systems were readily available, they might be difficult to interpret given that residential systems are often partly shaded or otherwise constrained by roof configurations that are at sub-optimal tilt or azimuth. Utility-scale projects, in contrast, are presumably less constrained by existing site conditions and better able to optimize these basic parameters, thereby generating performance data that are more normalized and easier to interpret. Similarly, even if known, the price at which third-party owners of residential PV systems sell electricity to site hosts is difficult to interpret, not only because of net metering and other state-level incentives that can affect the price, but also because residential PPAs are often priced only as low as they need to be in order to present an attractive value proposition relative to retail electricity prices (this is known as "value-based pricing"). In contrast, utility-scale solar projects must often compete (policy incentives notwithstanding) for PPAs against other generating technologies within competitive wholesale power markets, and therefore tend to offer PPA prices that reflect the minimum amount of revenue needed to recoup the project's initial cost, cover ongoing operating expenses, and provide a normal rate of return (this is known as "cost-plus" pricing). Whereas cost-plus pricing data provide useful information about the amount of revenue that solar needs in order to be economically viable in the market, value-based PPA price data are somewhat less useful in this regard, in that they often reflect the "price to beat" more than the lowest possible price that could be offered.

regulatory commissions, industry news releases, trade press articles, and communication with project owners and developers. Sample size also varies by chapter, and not all projects have sufficiently complete data to be included in all data sets. All data involving currency are reported in constant or real U.S. dollars – in this edition, 2014 dollars[6] – and all PPA price levelization uses a 7% real annual discount rate.

Defining "Utility-Scale"

Determining which electric power projects qualify as "utility-scale" (as opposed to commercial- or residential-scale) can be a challenge, particularly as utilities begin to focus more on distributed generation. For solar PV projects, this challenge is exacerbated by the relative homogeneity of the underlying technology. For example, unlike with wind power, where there is a clear difference between utility-scale and residential wind turbine technology, with solar, the same PV modules used in a 5 kW residential rooftop system might also be deployed in a 100 MW ground-mounted utility-scale project. The question of where to draw the line is, therefore, rather subjective. Though not exhaustive, below are three different – and perhaps equally valid – perspectives on what is considered to be "utility-scale":

- Through its Form 860, the Energy Information Administration ("EIA") collects and reports data on all generating plants larger than 1 MW, regardless of ownership or whether interconnected in front of or behind the meter (note: this report draws heavily upon EIA data for such projects).
- In their *Solar Market Insight* reports, Greentech Media and SEIA ("GTM/SEIA") define utility-scale by offtake arrangement rather than by project size: any project owned by or that sells electricity directly to a utility (rather than consuming it onsite) is considered a "utility-scale" project. This definition includes even relatively small projects (e.g., 100 kW) that sell electricity through a feed-in tariff ("FIT") or avoided cost contract (Munsell 2014).
- At the other end of the spectrum, some financiers define utility-scale in terms of investment size, and consider only those projects that are large enough to attract capital on their own (rather than as part of a larger portfolio of projects) to be "utility-scale" (Sternthal 2013). For PV, such financiers might consider a 20 MW (i.e., ~$50 million) project to be the minimum size threshold for utility-scale.

Though each of these three approaches has its merits, this report adopts yet a different approach: utility-scale solar is defined herein as any ground-mounted solar project that is larger than 5 MW_{AC}.

This definition is grounded in consideration of the four types of data analyzed in this report: installed prices, O&M costs, capacity factors, and PPA prices. For example, setting the threshold at 5 MW_{AC} helps to avoid smaller projects that are arguably more commercial in nature, and that may make use of net metering and/or sell electricity through FiTs or other avoided cost contracts (any of which could skew the sample of PPA prices reported in Chapter 6). A 5 MW_{AC} limit also helps to avoid specialized (and therefore often high-cost) applications, such as carports or projects mounted on capped landfills, which can skew the installed price sample. Meanwhile, ground-mounted systems are more likely than roof-mounted systems to be optimally oriented in order to maximize annual electricity production, thereby leading to a more homogenous sample of projects from which to analyze performance, via capacity factors. Finally, data availability is often markedly better for larger projects than for smaller projects (in this regard, even our threshold of 5 MW_{AC} might be too small).

Some variation in how utility-scale solar is defined is natural, given the differing perspectives of those establishing the definitions. Nevertheless, the lack of standardization does impose some limitations. For example, GTM/SEIA's projections of the utility-scale market (shown in Figure 1) may be useful to readers of this report, but the definitional differences noted above (along with the fact that GTM/SEIA reports utility-scale capacity in DC rather than AC terms) make it harder to synchronize the data presented herein with their projections. Similarly, institutional investors may find some of the data in this report to be useful, but perhaps less so if they are only interested in projects larger than 20 MW_{AC}.

Until consensus emerges as to what makes a solar project "utility-scale," a simple best practice is to be clear about how one has defined it (and why), and to highlight any important distinctions from other commonly used definitions – hence this text box.

[6] Conversions between nominal and real dollars use the implicit GDP deflator. Historical conversions use the actual GDP deflator data series from the U.S. Bureau of Economic Analysis, while future conversions (e.g., for PPA prices) use the EIA's projection of the GDP deflator in *Annual Energy Outlook 2015*.

Finally, we note that this report complements several other related studies and ongoing research activities, all funded as part of the Department of Energy's ("DOE") SunShot Initiative, which aims to reduce the cost of PV-generated electricity by about 75% between 2010 and 2020. For reference, this related work is briefly described in the text box below.

Related National Lab Research Products

Utility-Scale Solar is produced in conjunction with several related and ongoing research activities:

- ***Tracking-the-Sun*** is a separate annual report series produced by LBNL that focuses on residential and commercial solar and includes trends and analysis related to PV project pricing.

- ***The Open PV Project*** (openpv.nrel.gov) is an online data-visualization tool developed by the National Renewable Energy Laboratory (NREL) that incorporates data from *Tracking the Sun* and *Utility-Scale Solar*.

- ***Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections*** is an annual briefing produced jointly by NREL and LBNL that provides a broad overview of PV pricing trends, based on ongoing research activities at both labs.

- ***In-Depth Statistical Analyses*** of PV pricing data by researchers at LBNL and several academic institutions seek to further illuminate PV pricing dynamics and the underlying drivers, using more-refined statistical techniques.

These and other solar energy publications are available at: **http://emp.lbl.gov/projects/solar**

2. Technology Trends Among the Project Population

Before diving into project-level data on installed prices, operating costs, capacity factors, and PPA prices, this chapter analyses trends in utility-scale solar project technology and configurations among the *entire population* of projects from which later data samples are drawn. This population consists of 209 ground-mounted PV, CPV and CSP projects, each larger than 5 MW_{AC} and with an aggregate capacity of 7,910 MW_{AC}, that had achieved full commercial operation within the United States by the end of 2014.[7] The intent is to explore underlying trends in the characteristics of this fleet of projects that could potentially influence the cost, performance, and/or price data presented and discussed in later chapters. As with the data samples explored in later chapters, the total project population is broken out and described here by technology type – first PV (including CPV) and then CSP. For reasons described in the text box below, all capacity numbers (as well as other metrics that rely on capacity, like $/W installed prices) are expressed in AC terms, unless otherwise noted.

AC vs. DC: AC Capacity Ratings Are More Appropriate for Utility-Scale Solar

Because PV modules are rated under standardized testing conditions in direct current ("DC") terms, PV project capacity is also commonly reported in DC terms, particularly in the residential and commercial sectors. For utility-scale PV projects, however, the alternating current ("AC") capacity rating – measured by the combined AC rating of the project's inverters – is more relevant than DC, for two reasons:

1) All other conventional and renewable utility-scale generation sources (including concentrating solar power, or "CSP") to which utility-scale PV is compared are described in AC terms – with respect to their capacity ratings, their per-unit installed and operating costs, and their capacity factors.

2) Utility-scale PV project developers have, in recent years, increasingly oversized the DC PV array relative to the AC capacity of the inverters (described in more detail in this chapter, and portrayed in Figure 5). This increase in the "inverter loading ratio" boosts revenue and, as a side benefit, increases AC capacity factors. In these cases, the difference between a project's DC and AC capacity ratings will be significantly larger than one would expect based on conversion losses alone, and since the project's output will ultimately be constrained by the inverters' AC rating, the project's AC capacity rating is the more appropriate rating to use.

Except where otherwise noted, this report defaults to each project's AC capacity rating when reporting capacity (MW_{AC}), installed costs or prices ($/$W_{AC}$), operating costs ($/kW_{AC}-year), and AC capacity factor.

[7] With the exception of Chapter 6, which examines PPA prices for both online and planned projects, we do not include projects that have not yet achieved full commercial operation, unless multiple years lie between consecutive phases (in which case project development is more akin to the development of separate projects). One implication of this approach is that projects are attributed in their entirety to the year in which their last phase comes online, even though they may have been under construction (and even partially operating) for several years. We chose this approach because certain important project characteristics (such as project prices) are usually only reported for a project as a whole, rather than for its individual phases.

PV (194 projects, 6,236 MW_{AC})

At the end of 2014, 194 PV projects totaling 6,236 MW_{AC} were fully online in the United States and met the definition of utility-scale used in this report (ground-mounted and larger than 5 MW_{AC}).[8] These 194 projects, the first of which were installed in 2007, make up the total population of PV projects from which data samples are drawn in later chapters of this report. More than half of this capacity – i.e., 63 projects totaling 3,218 MW_{AC} – achieved commercial operation in 2014.

Figure 2 breaks out this capacity by module type and project configuration – i.e., projects that use crystalline silicon ("c-Si") versus thin-film modules,[9] and projects mounted at a fixed tilt instead of on a tracking device that follows the position of the sun.[10] Though thin-film modules powered two-thirds of the new utility-scale PV capacity installed in 2010, c-Si projects dominated in 2011, 2012, and 2013, accounting for 70% of all new utility-scale PV capacity installed in those three years. This trend reversed yet again in 2014, however, when the 6 largest projects built all used thin-film modules, resulting in a 70% market share.

Among the entire project sample that came online in 2014 (including both c-Si and thin-film projects) the number of projects using solar tracking technologies increased slightly from 55% in 2013 to 58% in 2014. In capacity terms, however, tracking projects decreased to 41% of new 2014 capacity (from 56% in 2013) as the three largest 2014 projects (Topaz, Agua Caliente and Desert Sunlight) all used fixed-tilt racking.

Notably, 12 of the 16 thin-film projects that came online in 2014 use single-axis tracking – a significant departure from just 2 tracking thin-film projects built prior to 2014. This shift is largely attributable to First Solar's acquisition of RayTracker's single-axis tracking technology back in 2011; First Solar deployed this technology in all but its four largest projects in 2014.[11] Tracking has historically not been as common among thin-film projects, largely because the lower efficiency of thin-film relative to c-Si modules requires more land area per nameplate MW – an expense that is exacerbated by the use of trackers (that said, the efficiency of First Solar's CdTe modules has been increasing over time).

[8] Because of differences in how "utility-scale" is defined (e.g., see the text box on page 3), the total amount of capacity in the PV project population described in this chapter cannot necessarily be compared to other estimates (e.g., from GTM Research and SEIA 2015) of the amount of utility-scale PV capacity online at the end of 2014.

[9] Module manufacturer First Solar, which produces CdTe modules, accounts for all new thin-film capacity added to the project population in 2014.

[10] All but two of the PV projects in the population that use tracking systems use single-axis trackers (which track the sun from east to west each day). In contrast, two recently built PV projects in Texas, along with the two CPV projects and one CSP power tower project (described later), use dual-axis trackers (i.e., east to west daily *and* north to south over the course of the year). For PV, where direct focus is not as important as it is for CPV or CSP, dual-axis tracking is a harder sell than single-axis tracking, as the roughly 10% boost in generation (compared to single-axis, which itself can increase generation by ~20%) often does not outweigh the incremental costs (and risk of malfunction), depending on the PPA price.

[11] The very large Topaz, Agua Caliente, and Desert Sunlight projects had all executed PPAs and were well under development (and perhaps even construction) prior to the acquisition of RayTracker. The large Antelope Valley project was in a similar position, but did manage to incorporate tracking in roughly 20% of the project.

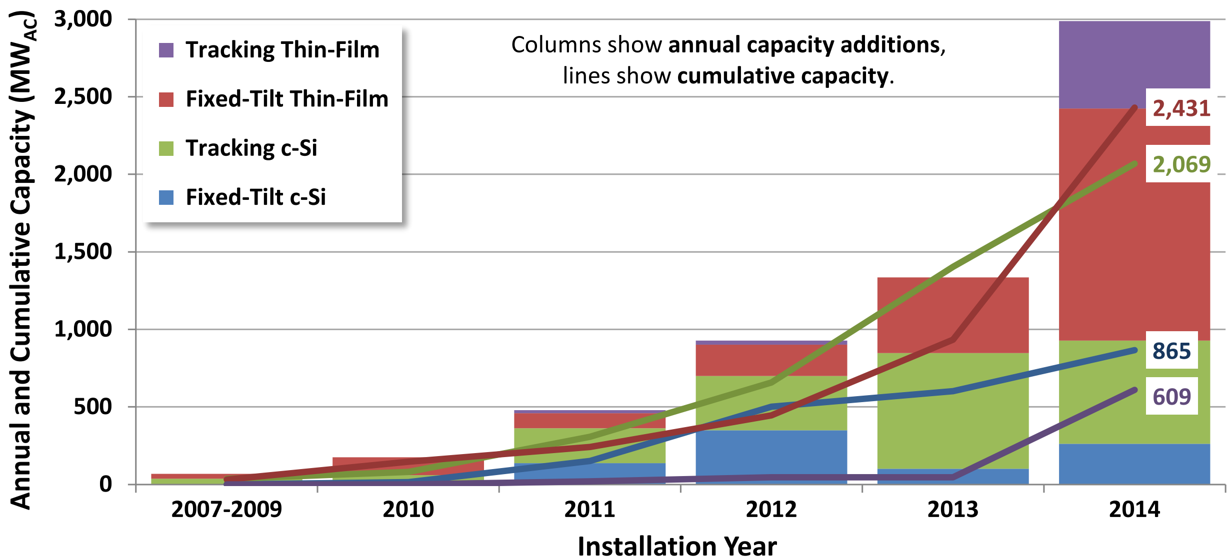


Figure 2. Capacity Shares of PV Module and Mounting Configurations by Installation Year

Figure 2 also breaks down the composition of *cumulative* installed capacity as of the end of 2014. Fixed-tilt thin-film (2,431 MW_{AC}) held a slight lead over tracking c-Si (2,069 MW_{AC}, but spread across more than twice as many projects), while fixed-tilt c-Si (865 MW_{AC}) and tracking thin-film (609 MW_{AC}) followed more distantly. Overall, the total project population as of the end of 2014 was split fairly evenly (in capacity terms) between fixed-tilt (55%) vs. tracking (45%) projects, and thin-film (53%) vs. c-Si projects (47%).

Figure 3 overlays the location of every utility-scale solar project in the LBNL population (including CPV and CSP projects) on a map of solar resource strength, as measured by global horizontal irradiance ("GHI").[12] Not surprisingly, most of the projects (and capacity) in the population are located in the southwestern United States,[13] where the solar resource is the strongest and where state-level policies (such as renewable portfolio standards, and in some cases state-level tax credits) encourage utility-scale solar development. As shown, however, utility-scale solar projects have also been built in various states along the east coast and in the Midwest, where the solar resource is not as strong; these installations have largely been driven by state renewable portfolio standards. Though there are obviously some exceptions, Figure 3 also shows a preponderance of tracking projects (both c-Si and, more recently, thin-film) in the high-GHI Southwest, compared to primarily fixed-tilt c-Si in the lower-GHI East.

[12] Global Horizontal Irradiance (GHI) is the total solar radiation received by a surface that is held parallel to the ground, and includes both direct normal irradiance (DNI) and diffuse horizontal irradiance (DIF). DNI is the solar radiation received directly by a surface that is always held perpendicular to the sun's position (i.e., the goal of dual-axis tracking devices), while DIF is the solar radiation that arrives indirectly, after having been scattered by the earth's atmosphere. The GHI data represent average irradiance from 1998-2009 (Perez 2012).
[13] As of the end of 2014, the Southwest (defined rather liberally here to include CA, NV, AZ, UT, CO, NM, and TX) accounted for 90% of the population's cumulative PV capacity, and 96% of its CSP capacity.

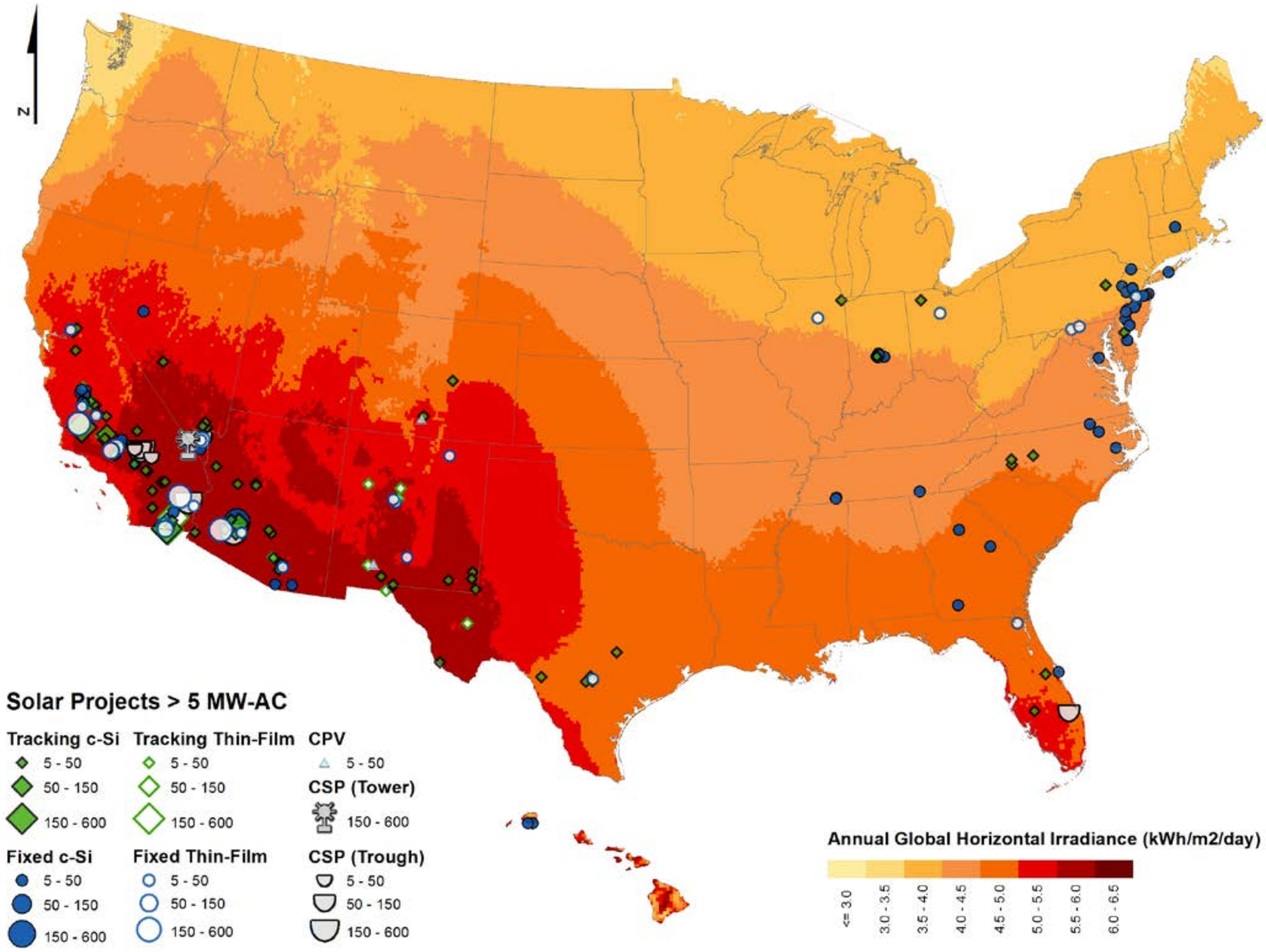


Figure 3. Map of Global Horizontal Irradiance (GHI) and Utility-Scale Solar Project Locations

While Figure 3 provides a static view of *where* and in what type of solar resource regime utility-scale solar projects within the population are located, knowing *when* each of these projects was built – and hence how the average resource quality of the project fleet has evolved over time – is also useful, for example, to help explain any observed trend in project-level capacity factors by project vintage (explored later in Chapter 5).

Figure 4 addresses this question by showing the capacity-weighted average GHI (in kWh/m^2/day) among PV projects built in a given year, both for the entire PV project population (solid black line) and broken out by fixed-tilt vs. tracking projects. Across the entire population, the average GHI has increased steadily over time, suggesting a relative shift in the population towards projects located in the high-GHI Southwest. Although the capacity-weighted averages for fixed-tilt and tracking projects are not too dissimilar, the 20th percentiles are markedly different, with fixed-tilt projects stuck around 4 kWh/m2/day, in contrast to much higher (and generally increasing by vintage) 20th percentile values for tracking projects. The wide distribution of fixed-tilt projects reflects the fact that – as shown previously in Figure 3 – most projects in the lower-GHI regions of the United States are fixed-tilt, yet very large fixed-tilt projects are also present in the high-GHI Southwest (often using CdTe thin-film technology, perhaps due to its greater tolerance for high-temperature environments[14]). Tracking projects, meanwhile, are concentrated primarily in the Southwest.

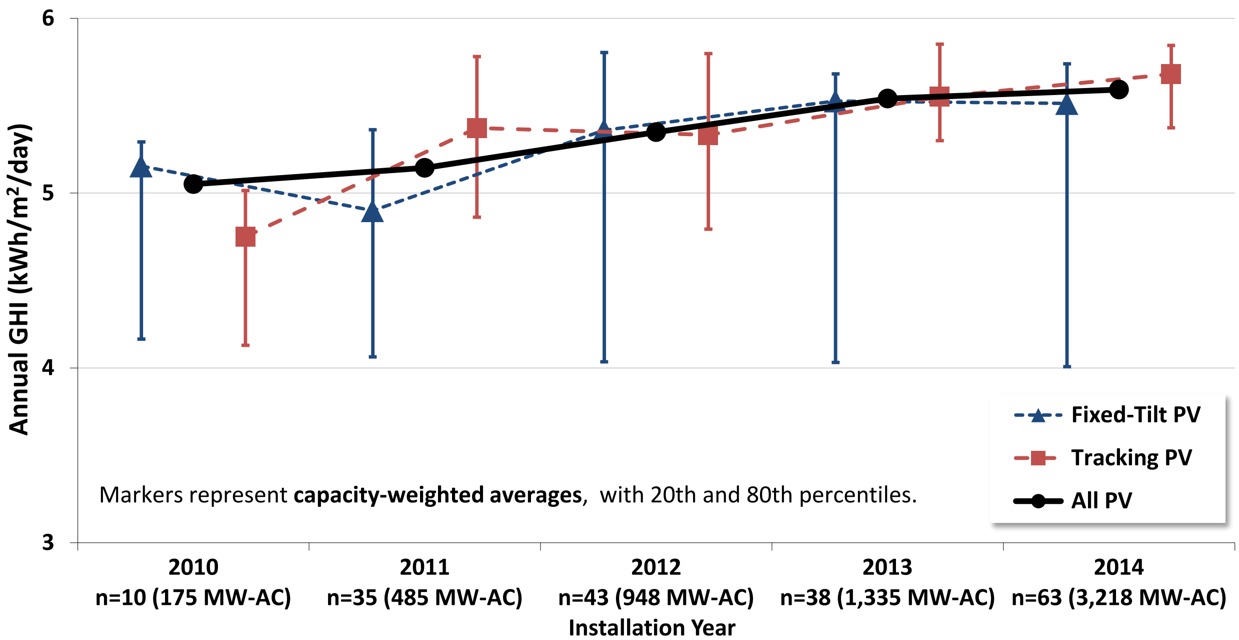


Figure 4. Trends in Global Horizontal Irradiance by Mounting Type and Installation Year

A second project-level characteristic that influences both installed project prices and capacity factors is the inverter loading ratio ("ILR"), which describes a project's DC capacity rating (i.e., the sum of the module ratings under standardized testing conditions) relative to its aggregate AC inverter rating.[15] With the cost of PV modules having dropped precipitously in recent years (and more rapidly than the cost of inverters), and with some utilities (particularly in California) offering time-varying PPA prices that favor generation during certain daylight hours, including late afternoon, many developers have found it economically advantageous to oversize the DC array relative to the AC capacity rating of the inverters. As this happens, the inverters operate closer to (or at) full capacity for a greater percentage of the day, which – like tracking – boosts the capacity factor,[16] at least in AC terms (this practice will actually *decrease* the capacity factor in DC terms, as some amount of power "clipping" will often occur during peak production

[14] The vast majority of thin-film capacity in the project population uses CdTe modules from First Solar. On its web site (First Solar 2015), First Solar claims that its CdTe technology provides greater energy yield (per nameplate W) than c-Si at module temperatures above 25° C (77° F) – i.e., conditions routinely encountered in the high-insolation Desert Southwest region.
[15] This ratio is referred to within the industry in a variety of ways, including: DC/AC ratio, array-to-inverter ratio, oversizing ratio, overloading ratio, inverter loading ratio, and DC load ratio (Advanced Energy 2014; Fiorelli and Zuercher - Martinson 2013). This report uses inverter loading ratio, or ILR.
[16] This is analogous to the boost in capacity factor achieved by a wind turbine when the size of the rotor increases relative to the turbine's nameplate capacity rating. This decline in "specific power" (W/m^2 of rotor swept area) causes the generator to operate closer to (or at) its peak rating more often, thereby increasing capacity factor.

periods[17]). Particularly under time-varying PPA prices that extend peak pricing into the morning and/or evening hours, the resulting boost in generation (and revenue) during the shoulder periods of each day outweighs the occasional loss of revenue from peak-period clipping (which may be largely limited to just the high-insolation summer months).

Figure 5 shows the capacity-weighted average ILR among projects built in each year, both for the total PV project population (solid black line) and broken out by fixed-tilt versus tracking projects. Across all projects, the average ILR has increased significantly over time, from around 1.2 for projects built in 2010 to 1.31 in 2013. In 2014, the capacity-weighted average declined slightly to 1.28, as a number of very large projects that had been under construction for several years finally came online; some of these projects have lower ILRs than their more-recently designed counterparts. But the 2014 median ILR (not shown) remained unchanged from 2013, at 1.29.

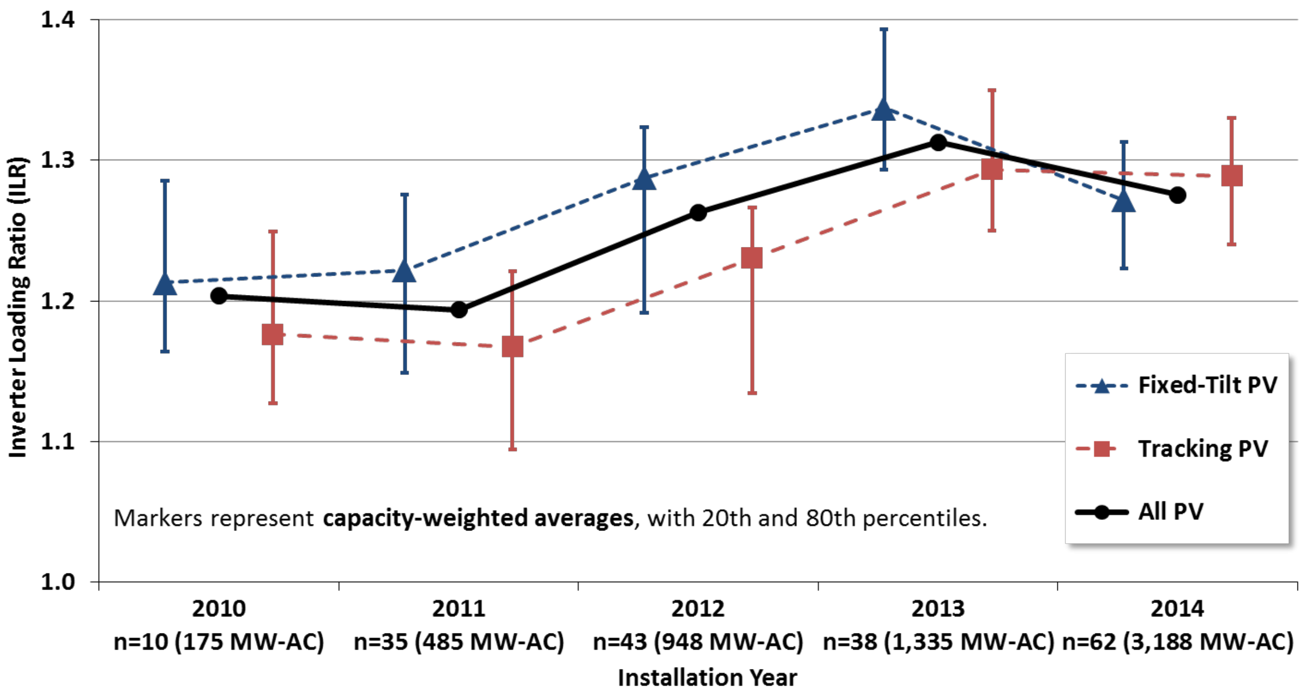


Figure 5. Trends in Inverter Loading Ratio by Mounting Type and Installation Year

With the exception of 2014 (again, influenced by these few large fixed-tilt projects with lower ILRs), fixed-tilt projects generally feature higher ILRs than tracking projects. This finding is consistent with the notion that fixed-tilt projects have more to gain from boosting the ILR in order to achieve a less-peaky, “tracking-like” daily production profile.

[17] Power clipping, also known as power limiting, is comparable to spilling excess water over a dam (rather than running it through the turbines) or feathering a wind turbine blade. In the case of solar, however, clipping occurs electronically rather than physically: as the DC input to the inverter approaches maximum capacity, the inverter moves away from the maximum power point so that the array operates less efficiently (Advanced Energy 2014, Fiorelli and Zuercher-Martinson 2013). In this sense, clipping is a bit of a misnomer, in that the inverter never really even “sees” the excess DC power – rather, it is simply not generated in the first place. Only *potential* generation is lost.

All else equal, Figure 4 and Figure 5 suggest that project-level capacity factors should increase among more recently built PV projects. This hypothesis is explored further (and confirmed) in Chapter 5.

CSP (15 projects, 1,673 MW_{AC})

After the nearly 400 MW_{AC} SEGS I-IX parabolic trough build-out in California in the 1980s and early 1990s, no other utility-scale CSP project was built in the United States until the 68.5 MW_{AC} Nevada Solar One trough project in 2007. This was followed by the 75 MW_{AC} Martin project in 2010 (also a trough project, feeding steam to a co-located combined cycle gas plant in Florida), and the 250 MW_{AC} Solana trough project in Arizona in 2013 (which also includes 6 hours of molten salt storage capacity).

In 2014, three additional CSP projects came online in California: two more trough projects without storage (Genesis and Mojave, each 250 MW_{AC}) and the first large-scale “solar tower” project in the United States (Ivanpah at 377 MW_{AC}). A second 110 MW_{AC} solar tower project with 10 hours of built-in thermal storage – Crescent Dunes in Nevada – has finished major construction activities but, at the time of writing, was still in the commissioning phase and not yet commercially online, and is thus excluded from this report. In the wake of this unprecedented buildout – totaling 1,127 MW_{AC} – of new CSP capacity in the past two years, there are currently no other major CSP projects moving towards construction in the United States.

3. Installed Prices

This chapter analyzes installed price data from a large sample of the overall utility-scale solar project population described in the previous chapter.[18] Specifically, LBNL has gathered installed price data for 176 utility-scale (i.e., ground-mounted and larger than 5 MW_{AC}) solar projects totaling 7,145 MW_{AC} and built between 2007 and 2014. The price sample is dominated by 170 PV projects (including 2 CPV projects) that total 5,874 MW_{AC} (i.e., PV accounts for 97% of all projects and 82% of all capacity in the installed price sample). It also includes 6 CSP projects totaling 1,270 MW_{AC}, consisting of the more recently built projects described in the previous chapter (rather than the older SEGS projects).

In general, only fully operational projects for which all individual phases were in operation at the end of 2014 are included in the sample[19] – i.e., by definition, our sample is backward-looking and therefore may not reflect installed price levels for projects that are completed or contracted in 2015 and beyond. Moreover, reported installed prices within our backward-looking sample may reflect transactions (e.g., entering into an Engineering, Procurement, and Construction or "EPC" contract) that occurred several years prior to project completion. In some cases, those transactions may have been negotiated on a forward-looking basis, reflecting anticipated future costs at the time of project construction. In other cases, they may have been based on contemporaneous costs (or a conservative projection of costs), in which case the reported installed price data may not fully capture recent reductions in component costs or other changes in market conditions.[20] For these reasons, the data presented in this chapter may not correspond to recent price benchmarks for utility-scale PV (Feldman et al. 2015), and may differ from the average installed prices reported elsewhere (Bloomberg New Energy Finance 2015; Fu et al. 2015; GTM Research and SEIA 2015). A text box later in this chapter (see *Bottom-Up vs. Top-Down*) explores this issue in more detail.

This chapter analyzes installed price trends among the sample of utility-scale projects described above. It begins with an overview of installed prices for PV (and CPV) projects over time, and then breaks out those prices by module type (c-Si vs. thin-film vs. CPV), mounting type (fixed-tilt vs. tracking), and system size. The chapter then provides an overview of installed prices for the six CSP projects in the sample. Sources of installed price information include the Treasury Department's Section 1603 Grant database, data from applicable state rebate and incentive programs, state regulatory filings, FERC Form 1 filings, corporate financial filings, interviews with developers and project owners, trade press articles, and data previously gathered by the National Renewable Energy Laboratory (NREL). All prices are reported in real 2014 dollars.

[18] Installed "price" is reported (as opposed to installed "cost") because in many cases, the value reported reflects either the price at which a newly completed project was sold (e.g., through a financing transaction), or alternatively the fair market value of a given project – i.e., the price at which it would be sold through an arm's-length transaction in a competitive market.
[19] In contrast, later chapters of this report do present data for individual phases of projects that are online, or (in the case of Chapter 6 on PPA prices) even for phases of projects or entire projects that are still in development and not yet operating.
[20] This reasoning may partially explain why the decline in installed prices presented in this chapter has seemingly not kept pace with the decline in PPA prices reported later in Chapter 6.

PV (170 projects, 5,874 MW_{AC}, including 2 CPV projects totaling 35 MW_{AC})

LBNL's sample of 170 PV (and CPV) projects totaling 5,874 MW_{AC} for which installed price estimates are available represents 87% of the total number of PV projects and 94% of the amount of capacity in the overall PV project population described in Chapter 2. Focusing just on those PV projects that achieved commercial operation in 2014, LBNL's sample of 55 projects totaling 3,052 MW_{AC} represents 87% and 95% of the total number of 2014 projects and capacity in the population, respectively.

Figure 6 shows installed price trends for PV (and CPV) projects completed from 2007 through 2014 in both DC and AC terms. Because PV project capacity is commonly reported in DC terms (particularly in the residential and commercial sectors), the installed cost or price of solar is often reported in $\$/W_{DC}$ terms as well (Barbose and Darghouth 2015; GTM Research and SEIA 2015). As noted in the text box (*AC vs. DC*) at the beginning of Chapter 2, however, this report analyzes utility-scale solar in AC terms. Figure 6 shows installed prices both ways (in both $\$/W_{DC}$ and $\$/W_{AC}$ terms) in an attempt to provide some continuity between this report and others that present prices in DC terms. The remainder of this chapter, however, as well as the rest of this document, report data exclusively in AC terms, unless otherwise noted.

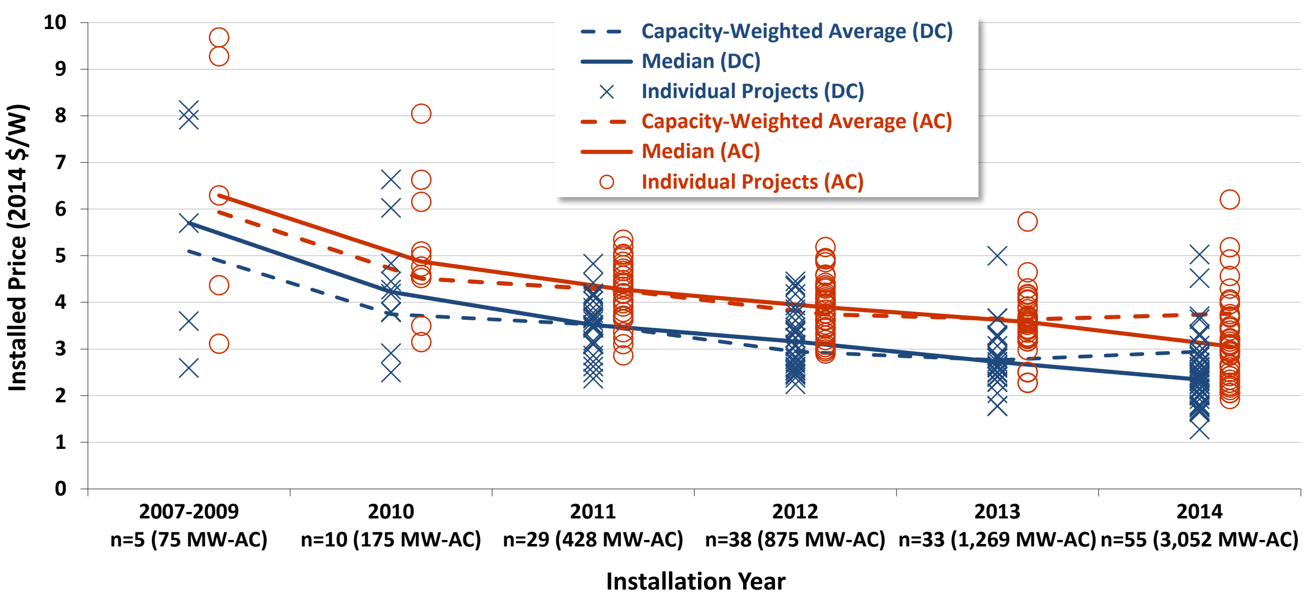


Figure 6. Installed Price of Utility-Scale PV and CPV Projects by Installation Year

As shown, the median utility-scale PV prices (solid lines) within our sample have declined fairly steadily in each year, to $\$3.1/W_{AC}$ (or $\$2.3/W_{DC}$) in 2014. This represents a price decline of more than 50% since the 2007-2009 period (and 37% since 2010). The lowest-priced projects among our 2014 sample of 55 PV projects were ~$\$2/W_{AC}$, with the lowest 20th percentile of projects having fallen considerably, from $\$3.2/W_{AC}$ in 2013 to $\$2.3/W_{AC}$ in 2014.

In contrast, capacity-weighted average prices (dashed lines) have declined more slowly through 2013, and even increased slightly in 2014 to $\$3.8/W_{AC}$ (or $\$2.9/W_{DC}$). The divergence between median and capacity-weighted average prices in 2014 can be explained by a number of very large PV projects that have been under construction for several years but that only achieved final commercial operation in 2014 (and so only entered our sample in 2014). These projects may have signed EPC contracts several years ago, perhaps at significantly higher prices than some of their smaller and more-nimble counterparts that started construction more recently.[21] Although in general we prefer capacity-weighted averages over medians,[22] the next graph will focus on medians rather than capacity-weighted averages in order to avoid the apparent distortion seen in Figure 6 for 2014.

While median prices in the sample have generally declined over time, there remains a considerable spread in individual project prices within each year. The overall variation in prices may be partially attributable to differences in module and mounting type – i.e., whether PV projects use c-Si or thin-film modules, and whether those modules are mounted at a fixed tilt or on a tracking system.

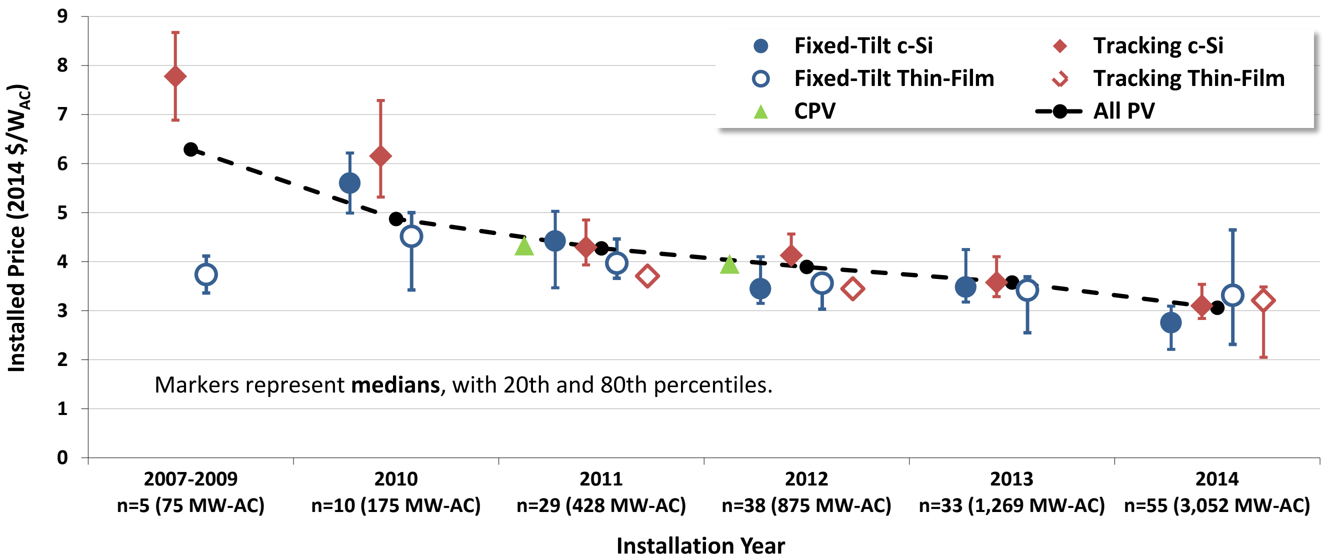


Figure 7. Installed Price of Utility-Scale PV and CPV Projects by Project Design and Installation Year

Figure 7 breaks out installed prices over time among these four combinations (and also includes the two CPV projects in the sample – but excludes several "hybrid" projects that feature a mix of

[21] For example, within our PPA price sample (described later in Chapter 6), the longest span between PPA execution date (as a proxy for EPC contract execution date) and commercial operation date for projects that came online in 2014 is 5 ¾ years, with the average lag for systems larger than 100 MW_{AC} being 3 ¾ years, compared to 2¼ years for systems smaller than 100 MW_{AC}. Because of their size, very large projects dominate the capacity-weighted average price in 2014 (eight projects larger than 100 MW_{AC} represent 74% of the capacity additions, but only 12.5% of new projects, in 2014).

[22] Whereas medians (and simple means) tell us about the typical project, capacity-weighted averages tell us more about the typical unit of capacity (e.g., the typical MW). Throughout most of this report, we are interested in analyzing the U.S. solar market in its entirety – e.g., deriving a representative installed price per unit of capacity (rather than per project), or a representative capacity factor or PPA price per MWh for the US fleet as a whole – and therefore tend to favor capacity-weighted averages over medians (or simple means). Given the apparent distortion noted above, however, as well as our increasing sample size over time (which lends itself more readily to medians), the use of medians seems more appropriate for this chapter – and will also align this report more closely with reported median prices for the residential and commercial PV systems in LBNL's companion *Tracking the Sun* series (e.g., see Barbose and Darghouth 2015).

module and/or mounting types, and so do not fit neatly into these four combinations). In 2014, the median price was \$2.8/W_{AC} for fixed-tilt c-Si projects, \$3.1/W_{AC} for tracking c-Si projects, \$3.3/W_{AC} for fixed-tilt thin-film projects, and \$3.2/W_{AC} for tracking thin-film projects.

Trends of particular note include:

- Although projects using c-Si modules were more expensive than projects using thin-film modules (e.g., by ~\$1.1/W_{AC} on average in 2010 for fixed-tilt projects), the average installed price of fixed-tilt c-Si and thin-film projects has converged over time, and even reversed in 2014 when c-Si held a ~\$0.6/W_{AC} advantage over thin-film projects completed in the same year (although some smaller fixed-tilt thin-film projects are offered at prices similar to the cheaper c-Si projects). This convergence has been led by the falling price of c-Si modules over time. As the price of c-Si projects has converged with thin-film, the predominance of c-Si projects has grown in both the installed price sample and the broader population (although this is not necessarily true for total interconnected capacity, given several very large thin-film projects that came online in 2014).

- Tracking systems remain slightly more expensive than fixed-tilt systems within the sample – a difference of about \$0.3/W_{AC} in 2014 among c-Si projects. As shown later in Chapter 5, however, this higher up-front expenditure results in greater energy production. In contrast, fixed-tilt thin-film projects do not appear to have a similar cost advantage over tracking thin-film projects, though this may be attributable to the previously noted price lags associated with several very large fixed-tilt thin-film projects (as well as perhaps to the vertical integration of First Solar and RayTracker).

- The two high-concentration CPV projects built in 2011 and 2012 exhibit installed prices that are comparable to the average PV pricing in the sample (yet, as shown later in Chapter 5, these two CPV projects have not performed as well as the average PV project). One or more low-concentration CPV projects (e.g., SunPower's new C7 technology powering an Apple server farm in Nevada) will enter the sample in 2015, providing additional data points.

Differences in project size may also explain some of the variation in installed prices, as PV projects in the sample range from 5.1 MW_{AC} to 585 MW_{AC}. Figure 8 investigates price trends by project size. To minimize the potentially confounding influence of price reductions over time, Figure 8 focuses on just those PV projects in the sample that became fully operational in 2014.

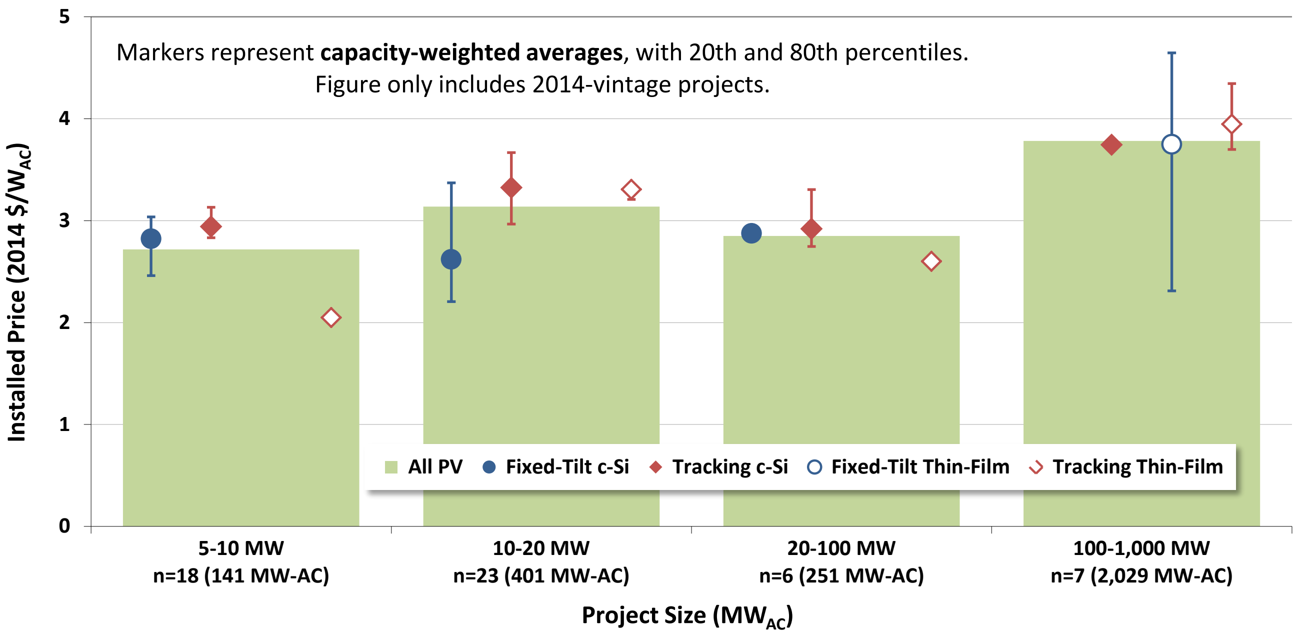


Figure 8. Installed Price of 2014 PV Projects by Size and Project Design

As shown, no consistent evidence of economies of scale can be found among the PV systems in our pricing sample that achieved commercial operation in 2014.[23] For example, there are no clear trends – either among the various mounting/module combinations (e.g., fixed-tilt c-Si) or for all projects in aggregate – among the first three project size bins shown in Figure 8, which range from 5 MW_{AC} up to 100 MW_{AC}. One possible explanation for this lack of trend is that economies of scale may be limited primarily to projects smaller than 5 MW_{AC} – which are excluded from our sample – given that the standardized and modular "power blocks" of module manufacturers like SunPower and First Solar are sized below this 5 MW_{AC} threshold. Another possibility is potential inconsistency in what costs or prices are captured among projects; e.g., some of the larger projects may include interconnection and transmission costs that are not present (or at least not reported) for smaller projects.

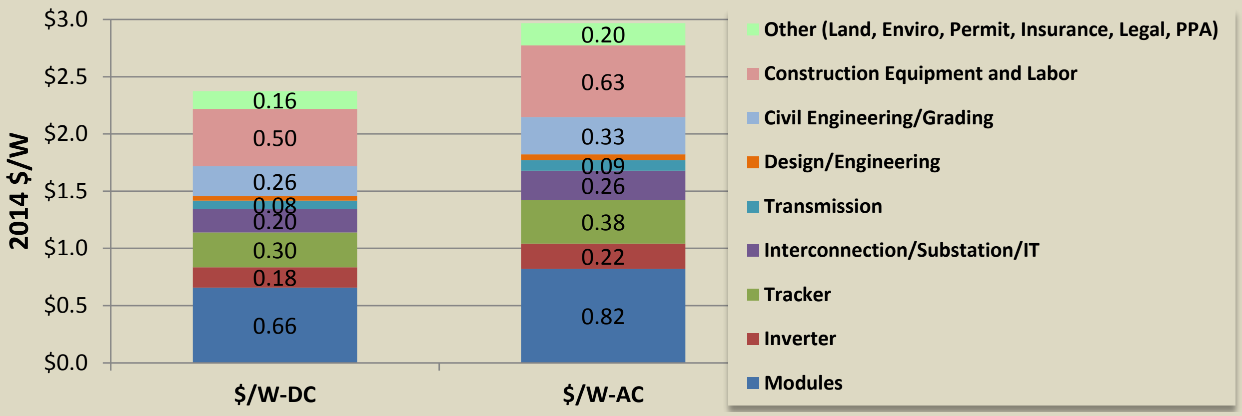
More notable in Figure 8 are the price *penalties* for projects larger than 100 MW_{AC}; two factors may contribute to these apparent *dis*economies of scale for very large projects. As discussed earlier, most of these very large projects have been under construction for several years and may therefore reflect higher module and EPC costs from several years ago. Moreover, these mega-scale projects – some of which involve more than 8 million modules and project sites of nearly 10 square miles – may face greater administrative, regulatory, and interconnection costs than do smaller projects.

[23] These empirical findings more or less align with recent modeling work from NREL (Fu et al. 2015), which also finds only modest scale economies for a 100 MW project compared to a 10 MW project, and no additional scale economies for projects larger than 100 MW.

Bottom-Up versus Top-Down: Different Ways to Look at Installed Project Prices

The installed prices analyzed in this chapter generally represent empirical *top-down* price estimates gathered from sources (e.g. corporate financial filings, FERC filings, the Treasury's Section 1603 grant database) that typically do not provide more granular insight into component costs. In contrast, several recent publications (Fu et al. 2015; GTM Research and SEIA 2015; Bloomberg New Energy Finance 2015) take a different approach of modeling total installed prices via a *bottom-up* process that aggregates modeled cost estimates for various project components to arrive at a total installed price. Each type of estimate has both strengths and weaknesses – e.g., top-down estimates often lack component-level detail but benefit from an empirical reality check, while bottom-up estimates provide more detail but rely on modeling.

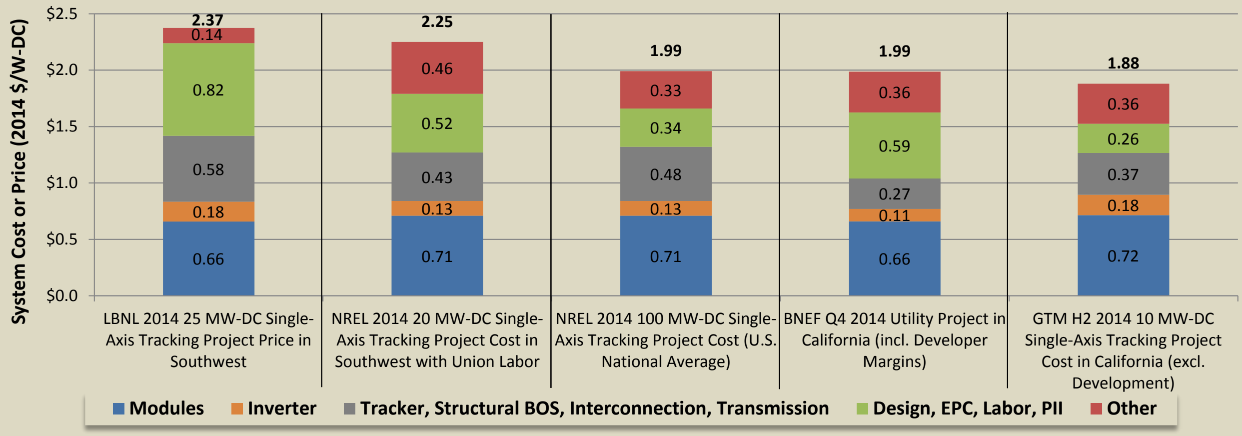
This text box explores to what extent the two different types of price estimates are in alignment, and where any differences lie. To aid in this comparison, LBNL obtained a detailed project cost breakdown for one of the PV projects in its price sample: a 20 MW_{AC} (25 MW_{DC}) single-axis tracking c-Si project that came online in the Southwest in 2014. The reported total installed price of this project – \$2.37/W_{DC} or \$2.97/W_{AC} – is comparable to other similar 2014 projects in the LBNL sample, suggesting that this project's detailed cost breakdown may be representative of other similar projects.



Representative Bottom-up Price of 2014 20 MW_{AC} Single-Axis Tracking System

The original cost breakdown for this project reported costs in 67 different categories that, for ease of presentation, are grouped into 9 larger cost bins in the figure above. As shown, the three major hardware components account for almost half of total costs, with 28% (\$0.66/W_{DC} / \$0.82/W_{AC}) coming from the modules, 13% (\$0.30/W_{DC} / \$0.38/W_{AC}) from the tracking/racking system, and 7.5% (\$0.18/W_{DC} / \$0.22/W_{AC}) from the inverters. Construction equipment and labor accounts for another 21% (\$0.50/W_{DC} / \$0.63/W_{AC}), while 11% (\$0.26/W_{DC} / \$0.33/W_{AC}) is attributable to civil engineering and grading.

The figure on the next page compares the cost breakdown for this seemingly representative project with modeled bottom-up estimates from NREL (Fu et al. 2015), BNEF (Bloomberg New Energy Finance 2015), and Greentech Media (GTM Research and SEIA 2015). Because each of these publications reports costs slightly differently, we had to create fairly broad (and hence rough) cost bins that reflect the "lowest common denominator" in order to compare them. In contrast to the rest of this report, costs in the next graph are shown exclusively in \$/W_{DC} to align with how they are reported in these other publications.



Comparison of Bottom-Up Utility-Scale PV Project Cost Estimates

As shown, the sample LBNL project has the highest installed price – despite reporting among the lowest module costs. That said, the total installed price of $2.37/W_{DC}$ is not too dissimilar from NREL's modeled bottom-up estimate of $2.25/W_{DC}$ for a similar project (i.e., a 20 MW_{DC} tracking c-Si project located in the Southwest and built with union labor). The other three estimates are all lower, with the NREL national and the BNEF model both arriving at about $2/W_{DC}$. The GTM estimate is the lowest as it excludes development costs (captured by the LBNL empirical breakdown); meanwhile, GTM's relatively high inverter costs include the AC subsystem, which other estimates include within interconnection costs. Finally, there are probably other differences in costs captured by the various estimates (e.g., financing costs, developer profit margins, transaction costs) that impede straightforward comparisons.

Among cost categories, the largest discrepancy between the sample LBNL project and the modeled bottom-up prices comes from the category that includes project design, EPC, labor, and permitting, interconnection and inspection ("PII"). One potential explanation for this discrepancy is that the bottom-up models may be modeling current EPC (or other) costs for projects that will be built in the future, whereas the sample LBNL project achieved commercial operation in 2014 and may therefore reflect, for example, EPC costs from some time ago (e.g., from before the project entered the construction phase).

Although it's difficult to pin down the exact reason for the discrepancy in installed prices shown in the figure above, this analysis nevertheless highlights the potentially substantial variation between empirical top-down and modeled bottom-up installed price estimates (and even among the various modeled bottom-up price estimates themselves), as well as the importance of understanding what each price estimate represents.

CSP (6 projects, 1,270 MW_{AC})

The CSP installed price sample excludes the nine SEGS projects built several decades ago, but includes all other concentrated solar thermal power (CSP) projects, totaling 1,270 MWAC, that were commercially operational at the end of 2014 and larger than 5 MW_{AC}. Five of these six projects feature parabolic trough technology, while the sixth uses power tower technology (consisting of a total of 3 solar towers). Another large solar tower project that had finished major construction activities in early 2014 but that had not yet entered commercial operation by the end of 2014 has been excluded from the sample.

Figure 9 breaks down these various CSP projects by size, technology and commercial operation date (from 2007 through 2014),[24] and also compares their installed prices to the median installed price of PV (from Figure 6) in each year from 2010 through 2014. The small sample size makes it difficult to discern any trends. In 2014 alone, for example, two equal-sized trough systems using similar technology (and both lacking storage) had significantly different installed prices ($5.10/W vs. $6.16/W). Meanwhile, the 2013 Solana trough system with six hours of storage was (logically) priced above both 2014 trough projects (at $6.76/W), while the 2014 power tower project was priced at the higher end of the range of the two trough projects. In general, CSP prices do not seem to have declined over time to any notable extent, in stark contrast to the median PV prices included in the figure.

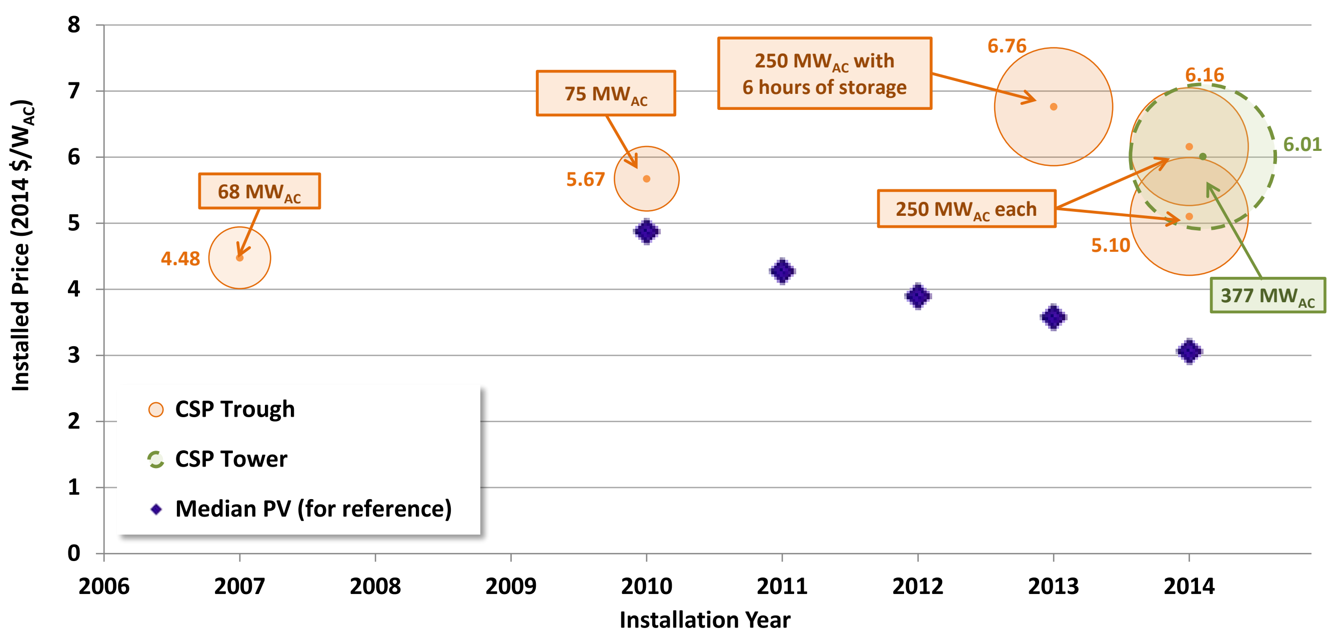


Figure 9. Installed Price of Utility-Scale CSP Projects by Technology and Installation Year

[24] The installed CSP prices shown in Figure 9 represent the entire project, including any equipment or related costs to enable natural gas co-firing.

4. Operation and Maintenance Costs

In addition to up-front installed project costs or prices, utility-scale solar projects also incur ongoing operation and maintenance ("O&M") costs, which are defined here to include only those direct costs incurred to operate and maintain the generating plant itself. In other words, O&M costs – at least as reported here – exclude payments such as property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead (all of which contribute to *total operating expenses*). This section reviews and analyzes the limited data on O&M costs that are in the public domain.

Empirical data on the O&M costs of utility-scale solar projects are hard to come by. Very few of the utility-scale solar projects that have been operating for more than a year are owned by investor-owned utilities, which FERC requires to report on Form 1 the O&M costs of the power plants that they own.[25] Even fewer of those investor-owned utilities that do own utility-scale solar projects actually report operating cost data in FERC Form 1 in a manner that is useful (if at all). It also appears that most investor-owned utilities (with the exception of Florida Power & Light) do not report empirical O&M costs for individual solar projects, but instead report average O&M costs across their entire fleet of PV projects, pro-rated to individual projects on a capacity basis. This lack of project-level granularity requires us to analyze solar O&M costs on an aggregate utility level rather than an individual project level. Table 1 describes our O&M cost sample and highlights the growing cumulative project fleet of each utility.

Year	PG&E[26]		PNM		APS[27]		FP&L	
	MW_{AC}	# projects	MW_{AC}	# projects	MW_{AC}	# projects	MW_{AC}	# projects
2011	N/A	N/A	N/A	N/A	51	3	110	3
2012	50	3	20	4	96	4	110	3
2013	100	6	42	4	136	6	110	3
2014	N/A	N/A	65	6	168	7	110	3
predominant technology	fixed-tilt c-Si		fixed-tilt thin-film		primarily tracking c-Si		mix of c-Si and CSP	

Table 1. Operation and Maintenance Cost Sample

Despite these limitations, Figure 10 shows average utility fleet-wide annual O&M costs for this small sample of projects in \$/kW$_{AC}$-year (blue solid line) and \$/MWh (red dashed line)[28]. The

[25] FERC Form 1 uses the "Uniform System of Accounts" to define what should be reported under "operating expenses" – namely, those operational costs of supervision and engineering, maintenance, rents, and training (and therefore excluding payments for property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead).

[26] As PG&E does not report operating costs for its solar projects on FERC Form 1, we turned to O&M costs reported in a CPUC compliance report (Middlekauff and Mathai-Jackson 2015) that unfortunately did not include usable cost data for 2014.

[27] APS reports O&M costs in FERC Form 1 only in an aggregated manner across customer classes (residential, commercial, and utility-scale). For lack of better data, we use their 168 MW_{AC} of total PV capacity (including residential and commercial) as a proxy for the 7 utility-scale solar plants with a combined capacity of 158 MW_{AC}.

whiskers represent both the lowest and the highest utility fleet-wide cost in each year. The dotted line refers to FP&L's project-specific annual O&M costs of its 75 MW CSP plant.

Average O&M costs for the PV plants within this sample have steadily declined from about \$30/kW$_{AC}$-year (or \$19/MWh) in 2011 to about \$17/kW$_{AC}$-year (\$8/MWh) in 2014. This decline could potentially indicate that utilities are capturing economies of scale as their PV project fleets grow over time, although the most recent drop from 2013 to 2014 may simply be a result of missing PG&E's costs for 2014 (PG&E's reported costs for 2012 and 2013 were above average). In 2014, all but one PV project had O&M costs of less than \$20/kW$_{AC}$-year (or \$11/MWh), which is lower than recent medium-term projections by bond rating agencies (see the O&M cost section of Bolinger and Weaver (2014)).

The only CSP plant in our sample reports higher O&M costs, in the \$40-\$50/kW$_{AC}$-year range for 2013 and 2014.

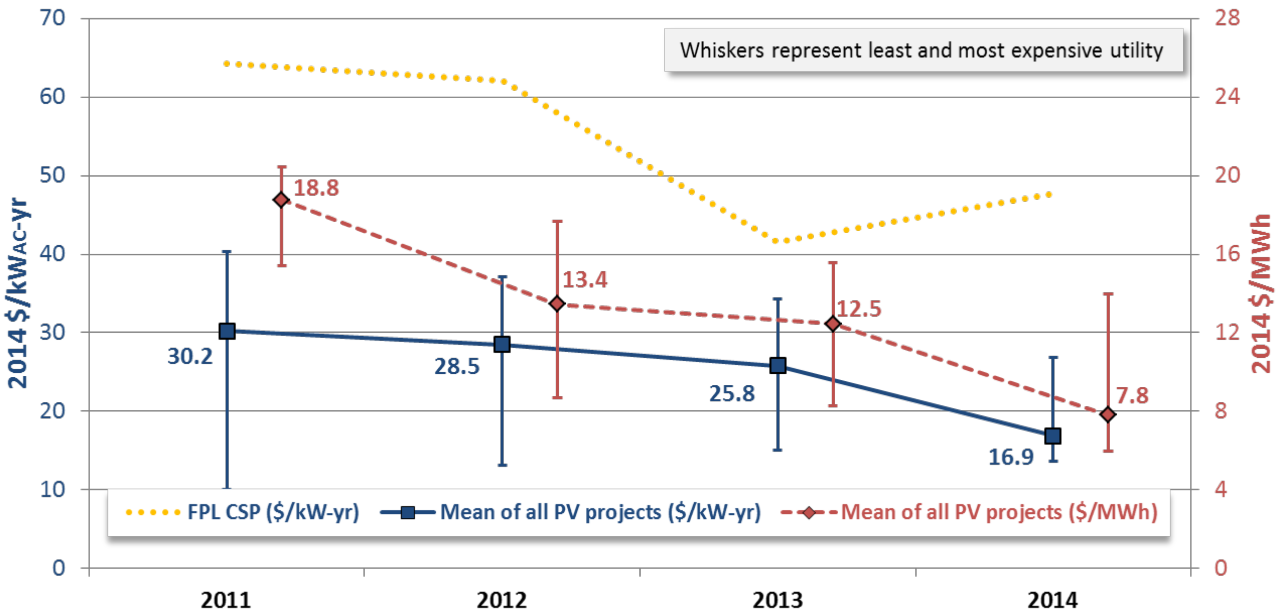


Figure 10. Empirical O&M Costs Over Time

As utility ownership of operating solar projects increases in the years ahead (and as those utilities that already own substantial solar assets but do not currently report operating cost data hopefully begin to do so, as required in FERC Form 1), the sample of projects reporting O&M costs should grow, potentially allowing for more interesting analyses in future editions of this report.

[28] O&M costs for the single CSP project (a 75 MW parabolic trough project) are only shown in \$/kW-year terms because this project provides steam to a co-located combined cycle gas plant.

5. Capacity Factors

At the close of 2014, more than 140 utility-scale solar projects (again, ground-mounted projects larger than 5 MW_{AC}) had been operating for at least one full year (and in some cases for many years), thereby enabling the calculation of capacity factors.[29] Sourcing net generation data from FERC Electronic Quarterly Reports, FERC Form 1, EIA Form 923, and state regulatory filings, this chapter presents net capacity factor data for 128 PV projects totaling 3,201 MW_{AC}, two CPV projects totaling 35 MW_{AC}, and thirteen CSP projects (a mix of parabolic trough and power tower projects, with and without thermal storage) totaling 1,390 MW_{AC} (and for which only the solar generation is reported here – no gas or oil augmentation is included). The PV sample size of 128 projects totaling 3.2 GW is double the amount analyzed in last year's edition of this report, and should once again increase significantly in next year's edition (along with more CSP as well), as the record amount of new utility-scale solar capacity that came online in 2014 will have its first full operating year in 2015.

PV (128 projects, 3,201 MW_{AC})

Project-level capacity factors for utility-scale PV projects can vary considerably, based on a number of factors, including (in approximate decreasing order of importance): the strength of the solar resource at the project site (measured in GHI with units $kWh/m^2/day$); whether the array is mounted at a fixed tilt or on a tracking mechanism; the DC capacity of the array relative to the AC inverter rating (i.e., the inverter loading ratio, or ILR); and the type of modules used (e.g., c-Si versus thin-film). Other factors such as tilt and azimuth will also play an obvious role, though since we focus only on ground-mounted utility-scale projects, our operating assumption is that these fundamental parameters will be equally optimized to maximize energy production across all projects.

One might also expect project vintage to play a role – i.e., that newer projects will have higher capacity factors because the efficiency of PV modules (both c-Si and thin-film) has increased over time. As module efficiency increases, however, developers simply either use fewer modules to reach a fixed amount of capacity (thereby saving on balance-of-system and land costs as well) or, alternatively, use the same number of modules to boost the amount of capacity installed on a fixed amount of land (directly reducing at least $\$/W_{DC}$ costs, if not also $\$/W_{AC}$ costs). In other words, for PV more than for other technologies like wind power, efficiency improvements over time show up primarily as cost savings rather than as higher capacity factors. Any increase in capacity factor by project vintage is therefore most likely attributable to a time trend in one of the other variables noted above – e.g., towards higher inverter loading ratios or greater use of tracking.

[29] Because solar generation is seasonal (generating more in the summer and less in the winter), capacity factor calculations should only be performed in full-year increments.

Figure 11 illustrates and supports this hypothesis, by breaking out the average net capacity factor ("NCF") by project vintage across the sample of projects built from 2010 through 2013 (and by noting the relevant average project parameters within each vintage). The capacity factors presented in Figure 11 represent *cumulative* capacity factors – i.e., calculated over as many years of data as are available for each individual project (a maximum of four years, from 2011 to 2014, in this case), rather than for just a single year (though for projects completed in 2013, only a single year of data exists at present) – and are expressed in *net*, rather than *gross*, terms (i.e., they represent the output of the project net of its own use). Notably, they are also calculated in AC terms (i.e., using the MW_{AC} rather than MW_{DC} nameplate rating),[30] yielding higher capacity factors than if reported in DC terms,[31] but allowing for direct comparison with the capacity factors of other generation sources (e.g., wind energy or conventional energy), which are also calculated in AC terms.

As shown, the average capacity factor increases only slightly from 2010- to 2011-vintage projects, due primarily to a higher proportion (in capacity terms) of projects using tracking among 2011-vintage projects, given virtually no change in the average ILR or GHI across these two vintages. Projects built in 2012 and especially 2013, however, have progressively higher capacity factors on average, driven by an increase in both average ILR and GHI in each year.

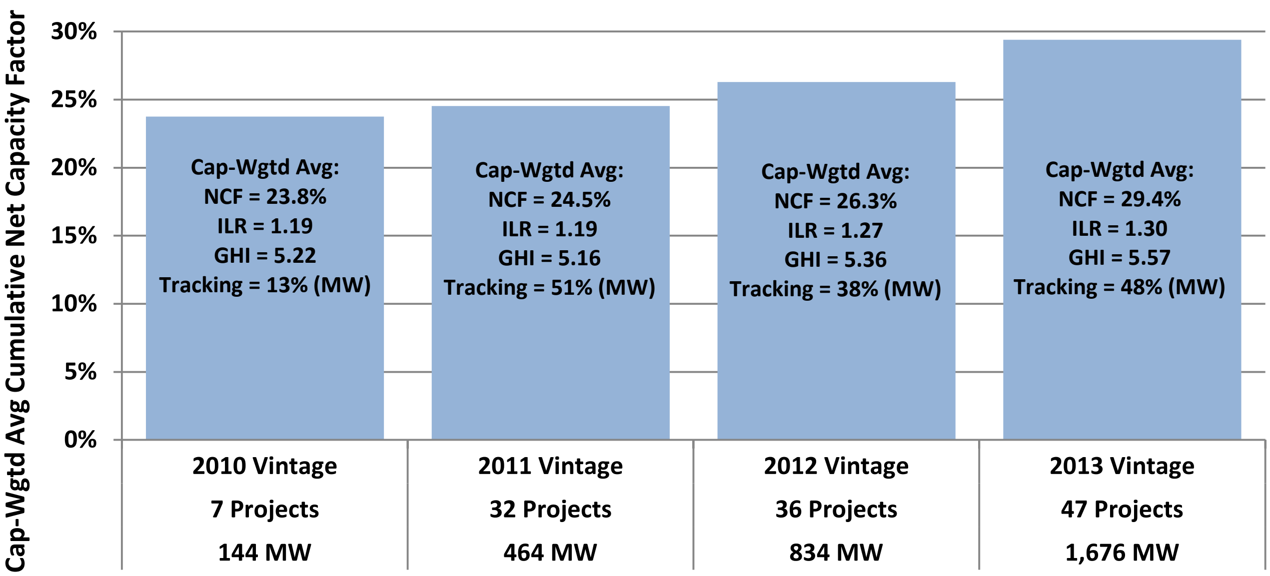


Figure 11. Cumulative PV Capacity Factor by Project Vintage: 2010-2013 Projects Only

Because Figure 11 analyzes *cumulative* capacity factors, one other possible explanation for the upward trend by vintage could be if the solar resource across the United States were significantly stronger in 2014 than in 2011-2013. If this were the case – which seems unlikely based on ex-post annual solar resource data (3Tier 2013; Vaisala 2014; Vaisala 2015) – then 2013-vintage projects might be expected to exhibit higher cumulative capacity factors than 2010-2012

[30] The formula is: Net Generation (MWh_{AC}) over Single- or Multi-Year Period / [Project Capacity (MW_{AC}) * Number of Hours in that Same Single- or Multi-Year Period].

[31] For example, a project with a 30% capacity factor in AC terms would have a 25% capacity factor in DC terms at an inverter loading ratio of 1.20, and a 20% capacity factor in DC terms at an inverter loading ratio of 1.50.

projects, given that 2014 is the only applicable performance year for a 2013-vintage project. To check against this possibility, Figure 12 replicates Figure 11, but based on single-year 2014 capacity factors rather than cumulative capacity factors. In other words, each vintage is measured based on its performance during the same single year – 2014 – rather than over a one- to four-year period, depending on vintage. As shown, the upward trend still holds, suggesting that ILR, GHI, and tracking are the true drivers.[32]

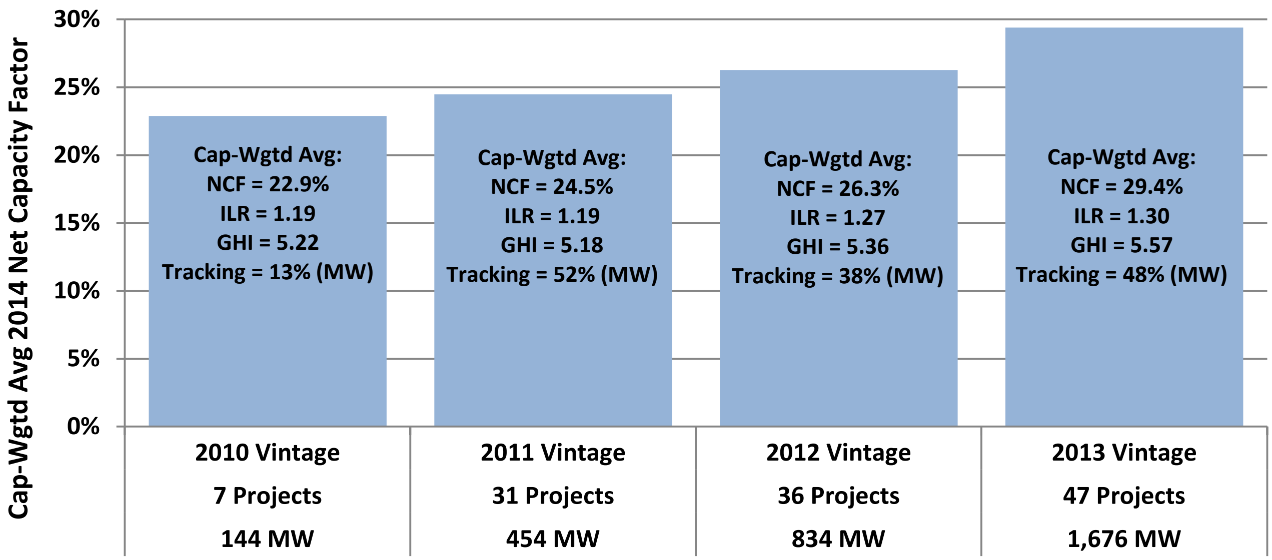


Figure 12. 2014 PV Capacity Factor by Project Vintage: 2010-2013 Projects Only

To the extent that this observable time trend in net capacity factor by project vintage is, in fact, attributable to a time trend in one or more of the other variables noted, it is perhaps best to measure the effect of those other variables directly. Figure 13 does just that, by categorizing the entire data sample in four different ways: by solar resource strength (in GHI terms), by fixed-tilt versus tracking systems, by the inverter loading ratio, and by module type (c-Si versus thin-film). The capacity-weighted average net capacity factor across the entire sample is 27.5%, the median is 26.5%, and the simple average is 25.6%, but there is a wide range of individual project-level capacity factors (from 14.8% to 34.9%) around these central numbers.

[32] There is one less project in the sample for Figure 12 than for Figure 11, due to 2014 net generation data not yet being available for one project in New Jersey.

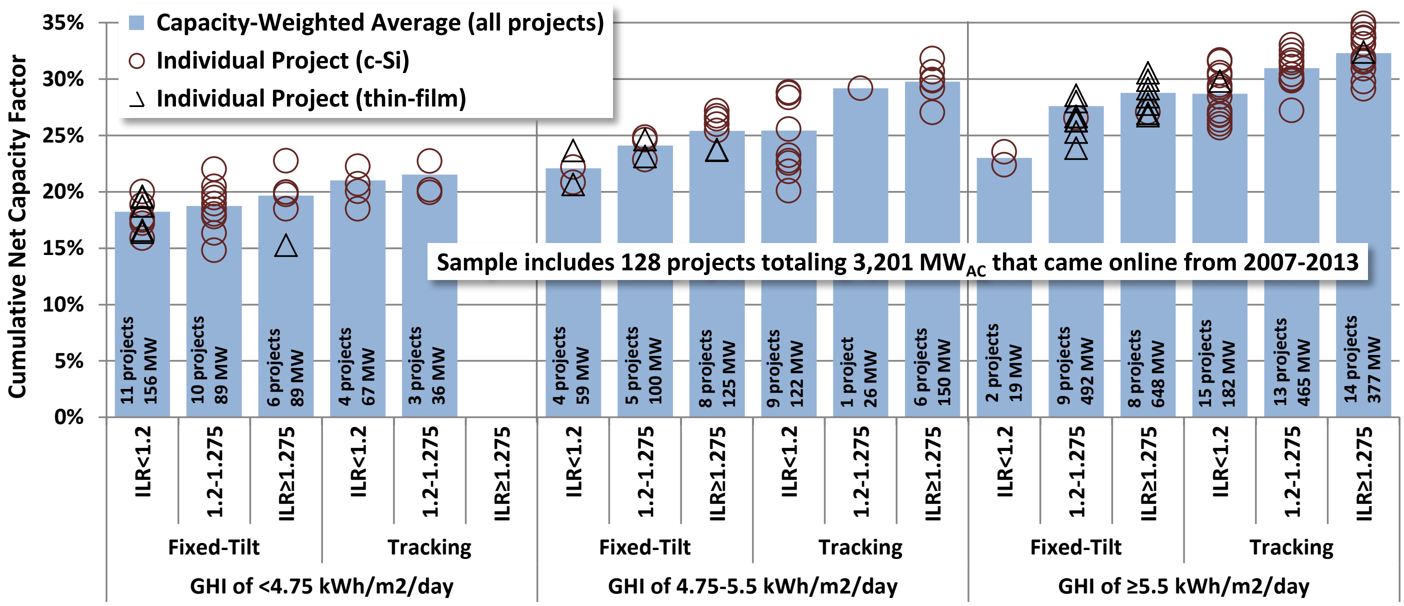


Figure 13. Cumulative PV Capacity Factor by Resource Strength, Fixed-Tilt vs. Tracking, Inverter Loading Ratio, and Module Type

Each of the four variables explored in Figure 13 is discussed in turn below.

- **Solar Resource:** Each project in the sample is associated with a global horizontal irradiance (GHI) value derived from the map shown earlier in Figure 3. Solar resource bin thresholds (<4.75, 4.75-5.5, and ≥5.5 kWh/m^2/day GHI) were chosen to ensure that a sufficient number of projects fall within each bin.[33] Not surprisingly, projects sited in stronger solar resource areas have higher capacity factors, all else equal. The difference can be substantial: the capacity-weighted average net capacity factors in the highest resource bin, for example, average 8% higher (in absolute terms) than their counterparts in the lowest resource bin (with the range extending 5-9% depending on fixed-tilt versus tracking and the inverter loading ratio).

- **Fixed-Tilt vs. Tracking:** Tracking (all single-axis in this sample) boosts average capacity factor by 3-4% on average (in absolute terms), depending on the resource bin (4% on average across all three resource bins).

- **Inverter Loading Ratio (ILR):** Figure 13 breaks the sample down further into three different inverter loading ratio bins: <1.2, 1.2-1.275, and ≥1.275.[34] The effect on average capacity factor is noticeable: across all resource bins and fixed/tracking bins, the absolute difference in capacity factor between the highest and lowest inverter loading ratio bin ranges from 1% to 6% (for an average of 4%).

[33] Thirty-four projects totaling 436 MW fall into the lowest resource category of less than 4.75 kWh/m^2/day, 33 projects totaling 582 MW fall into the middle resource category of between 4.75 and 5.5 kWh/m^2/day, and 61 projects totaling 2,183 MW fall into the highest resource category of at least 5.5 kWh/m^2/day.

[34] These ILR bins were chosen to ensure a roughly equal number of projects in each bin. The lowest ILR bins include 45 projects totaling 605 MW$_{AC}$, the middle bins include 44 projects totaling 1,208 MW$_{AC}$, and the highest bins include 42 projects totaling 1,388 MW$_{AC}$.

- **Module Type:** Figure 13 differentiates between projects using c-Si and thin-film modules by the shape and color of the markers denoting individual projects (the capacity-weighted averages include *both* c-Si and thin-film projects). Though somewhat difficult to tease out, the differences in project-level capacity factors by module type are generally small (smaller than for the other variables discussed above), and do not appear to exhibit any sort of pattern. That said, the prevalence of fixed-tilt thin-film projects within the highest resource bin is noticeable. As mentioned in an earlier section of this report, however, many of the new thin-film projects completed in 2014 (which will enter our capacity factor sample in next year's report) have deployed single-axis trackers.

CPV (2 projects, 35 MW_{AC})

The two CPV-only projects in the sample (the 5 MW_{AC} Hatch and the 30 MW_{AC} Cogentrix Alamosa projects) use virtually the same high-concentration technology (from Amonix), and both appear to be underperforming – both relative to publicly stated expectations and to how a single-axis tracking PV project would probably have performed in similar conditions. In November 2011, a few months after Hatch came online and a few months before Alamosa went online, a conference presentation from Amonix suggested a 31.5% capacity factor for Hatch and a 32.5% capacity factor for Alamosa (Pihowich 2011).[35] This 31.5-32.5% range is consistent with the empirical PV capacity factors seen in the second column from the right in Figure 13, which – except for the fact that they feature dual-axis, rather than single-axis, tracking – is where these two CPV projects would otherwise fall based on resource strength and inverter loading ratio. Actual experience to date, however, has been below this range: Hatch's 20.9% capacity factor in 2012 dropped to 18.5% in 2013 and 18.1% in 2014, while Cogentrix Alamosa posted a 24.9% capacity factor in 2013, followed by 24.2% in 2014.[36] The 2013 and 2014 capacity factors may have been reduced somewhat by the reportedly below-average insolation levels in the southwestern United States during the summers of 2013 and 2014 (3Tier 2013; Vaisala 2014; Vaisala 2015).[37]

[35] The Amonix slide deck (Pihowich 2011) contains conflicting information: it lists expected generation numbers that equate to a 31.5% capacity factor for Hatch, yet also states a slightly lower capacity factor estimate of 29.4% – either of which is higher than actual experience. Meanwhile, documents from El Paso Electric (the offtaker) list 9,189 MWh, or a 20.8% capacity factor, as the expected output of Hatch (the project met this expectation in 2012, but fell short in 2013 and 2014). For Cogentrix Alamosa, an April 2011 environmental assessment prepared for the DOE's Loan Program Office assumed a 29% capacity factor, although the current Loan Program Office project description notes annual generation of 58,000 MWh, equivalent to just 21.9% (well below the >24% achieved to date). The reason for these disparate expectations (for both projects) is not clear, though one potential explanation might have to do with timing – i.e., the current El Paso Electric and Loan Program Office numbers might be more recent, therefore potentially reflecting some degree of actual experience.

[36] A third project that includes a mix of PV and CPV technologies – the 6.9 MW_{AC} SunE Alamosa project – has performed better than the two CPV-only projects, having logged a 28.7% cumulative capacity factor over six full years of operation (from 2008-2013). The CPV portion of the project, however, only accounts for about 12% of the project's total capacity (the rest being PV with diurnal (~80%) or seasonal (~7%) tracking), and unfortunately, the project-level net generation data are not granular enough to enable a determination of how the CPV and PV portions of this project have performed independently.

[37] The entire year 2014 was an average to slightly above average solar year in the West, and an average to slightly below average solar year elsewhere in the continental United States. These annual averages mask important seasonal divergences, however – e.g., the above-average insolation tended to be concentrated in the less-important

CSP (13 projects, 1,390 MW_{AC})

Three new CSP projects totaling 892 MW_{AC} achieved commercial operation in late 2013, providing a significant boost to this year's CSP capacity factor sample. Solana is a 250 MW_{AC} (net) parabolic trough project with six hours of molten salt storage located in Arizona; Genesis is a 250 MW_{AC} (net) parabolic trough project without storage located in California; and Ivanpah is a 377 MW_{AC} (net) power tower project without storage located in California.

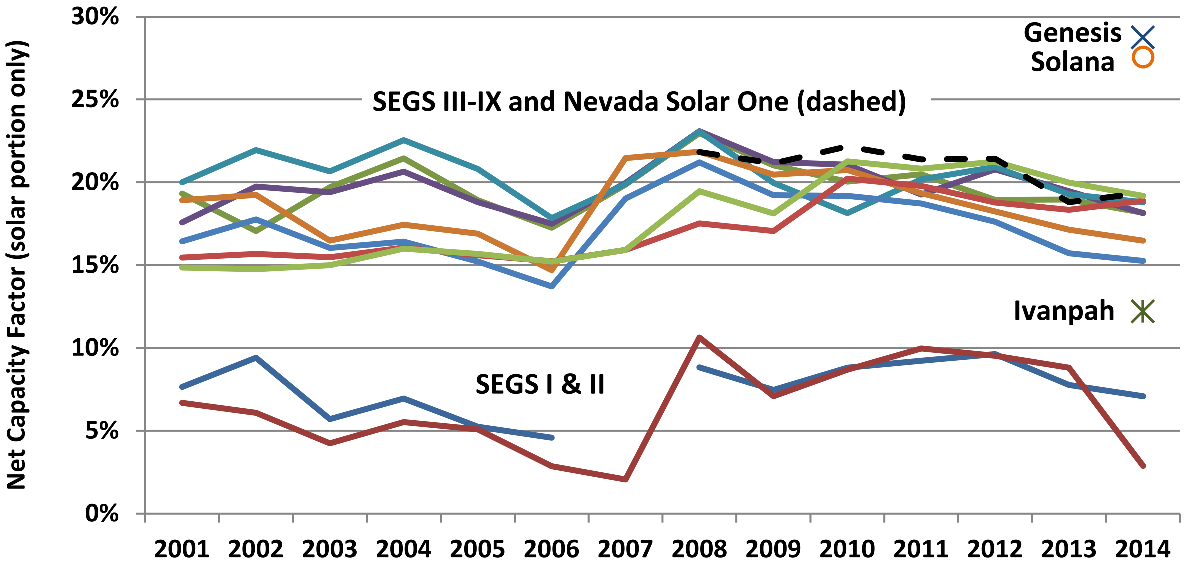


Figure 14. Capacity Factor of CSP Projects (Solar Portion Only) Over Time

Figure 14 shows the net capacity factors by calendar year from just the solar portion (i.e. no augmentation with natural gas or fuel oil is included in Figure 14 [38]) of our CSP project sample. The two new trough projects performed at roughly 28-29% capacity factors in 2014, while the Ivanpah power tower project performed at ~12% capacity factor. For at least Solana (with 6 hours of storage) and Ivanpah, these first-year numbers are below long-term expectations of 41% and 27%, respectively, and are projected to improve in future years as these projects overcome typical start-up challenges and are fine-tuned for optimal performance (Danko 2015; Stern 2015).[39] Indeed, the performance of these two projects has already improved somewhat in the

non-summer months, while the critical months of May through September were generally below average across much of the United States, including the Southwest (Vaisala 2014; Vaisala 2015).

[38] Many of these projects also use gas-fired turbines to supplement their output (e.g., during shoulder months, into the evening, or during cloudy weather). In the case of Nevada Solar One, for example, gas-fired generation has boosted historical capacity factors by twenty to forty basis points depending on the year (e.g., from 19.4% solar-only to 19.8% gas-included in 2014), with gas usage most often peaking in the spring and fall (shoulder months). The SEGS projects use relatively more gas-fired generation, which boosted their aggregate capacity factors by 60-200 basis points in 2014, depending on the project. The Ivanpah power tower project also burns gas – and reportedly more than originally anticipated (Danko 2015) – though data on its gas-fired generation in 2014 were not available at the time of writing.

[39] Ivanpah documentation suggests that this initial ramp-up could last as long as four years (Danko 2015).

first half of 2015.[40] Even despite these teething issues, however, the two new trough projects performed significantly better in 2014 than the existing fleet of ten older trough projects in the sample, including the nine SEGS plants (totaling 392 MW_{AC}) that have been operating in California for more than twenty years, and the 68.5 MW_{AC} Nevada Solar One trough project that has been operating in Nevada since mid-2007.[41]

These ten older trough projects tend to fall into two groupings, with SEGS I and II set apart from the rest by significantly lower capacity factors, perhaps attributable to some combination of separate ownership from SEGS III-IX as well as different plant characteristics (such as the size of the collector field relative to the capacity and efficiency of the steam turbine). Nearly all of these projects experienced lower solar-only capacity factors in 2013 and 2014 than in other recent years. This decline is potentially attributable in part to inter-year variations in the solar resource, which was below average in the southwestern United States (where these projects are located) during the summers of 2013 and 2014 (3Tier 2013; Vaisala 2014; Vaisala 2015), with summer being particularly important for CSP projects.

Looking ahead, another 250 MW_{AC} (net) parabolic trough project in California without storage (Mojave) achieved commercial operation in late 2014, and so will enter our capacity factor sample in 2015. A second power tower project – the 110 MW Crescent Dunes project in Nevada, with 10 hours of storage – is expected to be placed in service later in 2015 after a prolonged commissioning process. Along with the three new projects added to the sample this year (which should continue to mature over the next few years), these two new additions will expand the CSP performance data set in future years.

[40] For example, Ivanpah generated 309,913 MWh in the first six months of 2015 (for an annualized capacity factor of 18.2%), compared to 173,138 MWh in the first six months of 2014 (an annualized capacity factor of 10.2%). For Solana, the corresponding numbers are 352,569 MWh (32.5%) vs. 314,906 MWh (29.0%).
[41] One additional parabolic trough project – the 75 MW_{AC} Martin project in Florida – is excluded from the analysis due to data complications. Specifically, since 2011, the Martin project has been feeding steam to a co-located combined cycle gas plant, and a breakdown of the amount of generation attributable to solar versus gas is not readily available.

6. Power Purchase Agreement ("PPA") Prices

The cost of installing, operating, and maintaining a utility-scale solar project, along with its capacity factor – i.e., all of the factors that have been explored so far in this report – are key determinants of the price at which solar power can be profitably sold through a long-term power purchase agreement ("PPA"). Relying on data compiled from FERC Electronic Quarterly Reports, FERC Form 1, EIA Form 923, and a variety of regulatory filings, this section presents trends in PPA prices among a large sample of utility-scale solar projects in the U.S. The sample includes a total of 109 contracts totaling 8,578 MW_{AC} and broken out as follows: 100 PV PPAs totaling 7,234 MW_{AC}, two CPV PPAs totaling 35 MW_{AC}, one 7 MW_{AC} PPA that is a mix of PV and CPV, and 6 CSP PPAs (four parabolic trough, two power tower) totaling 1,301 MW_{AC}.

The population from which this sample is drawn includes only those utility-scale projects that sell electricity (as well as the associated capacity and renewable energy credits or "RECs") in the wholesale power market through a long-term, bundled PPA. Utility-owned projects, as well as projects that benefit from net metering or customer bill savings, are therefore not included in the sample. We also exclude those projects that unbundle and sell RECs separately from the underlying electricity, because in those instances the PPA price alone does not reflect the project's total revenue requirements (at least on a post-incentive basis). PPAs resulting from Feed-in Tariff ("FiT") programs are excluded for similar reasons – i.e., the information content of the pre-established FiT price is low (most of these projects do not exceed the 5 MW_{AC} utility-scale threshold anyway). In short, the goal of this chapter is to learn how much post-incentive revenue a utility-scale solar project requires to be viable.[42] As such, the PPA sample comes entirely from utility-scale projects that sell bundled energy, capacity, and RECs to utilities (both investor-owned and publicly-owned utilities) or other offtakers through long-term PPAs resulting from competitive solicitations or bilateral negotiations.[43] As a practical matter, this means that we exclude "avoided cost" contracts – discussed in the text box on the next page – from our PPA price sample as well.

[42] Using PPA prices for this purpose reflects an implicit assumption that PPA prices will always be sufficient to cover all costs and provide a normal rate of return. This may not always be the case, however, if projects underperform relative to expectations or have higher-than-anticipated operating costs. In general, the project sponsor and investors bear these risks (to varying degrees, depending on the specifics of their contractual arrangements).

[43] Because all of the PPAs in the sample include RECs (i.e., transfer them to the power purchaser), we need not worry too much about REC price trends in the unbundled REC market. It is, however, worth noting that some states (e.g., Colorado) have implemented REC "multipliers" for solar projects (whereby each solar REC is counted as more than one REC for RPS compliance purposes), while others have implemented solar "set-asides" or "carve-outs" (requiring a specific portion of the RPS to be met by solar) as a way to encourage specifically solar power development. In these instances, it is possible that utilities might be willing to pay a bit more for solar through a bundled PPA than they otherwise would be, either because they need to in order to comply with a solar set-aside, or because they know that each bundled solar REC has added value (in the case of a multiplier). So even though REC prices do not directly affect the analysis in this report, policy mechanisms tied to RECs might still influence bundled PPA prices in some cases – presumably to the upside.

Trend to Watch: The Rise (and Fall?) of "Avoided Cost" Markets

As discussed in the text, virtually all of the PPAs analyzed in this chapter result from competitive solicitations or some other form of bilateral negotiation. Yet as the cost of solar has fallen to more-competitive levels, a "new" market for utility-scale solar (which is actually one of the *oldest* markets for renewables in the United States, in existence ever since the Public Utility Regulatory Policies Act, or PURPA, was signed into law in 1978) has emerged over the past year or so. Specifically, PURPA requires utilities to purchase electricity from "qualifying facilities" (including solar and wind projects) at prices that represent their "avoided cost" – i.e., what they would pay for the same amount of electricity generated by a non-qualifying facility. As a matter of policy, we exclude these "avoided cost" contracts from our PPA price sample, because they are FiT-like and, in some states, also involve unbundling RECs; yet, as discussed below, this growing market is not to be ignored.

Solar developers have been capitalizing on these avoided cost contracts for several years now in North Carolina, though the 5 MW capacity limit in that state means that most of the more than 150 projects that are operational in North Carolina fall below our threshold of what is considered to be "utility-scale." But in the past year, numerous avoided cost contracts for larger projects have been announced in other states that had not previously seen any solar development to speak of. For example:

- In Utah, at least two new 80 MW_{AC} PV projects (in addition to a number of smaller projects) should begin commercial operation by the end of 2015, selling electricity to PacifiCorp through 20-year avoided cost contracts. More than 700 MW of additional solar capacity is under development in Utah and could come online in 2016 under these same avoided cost contracts. Although the prices for these larger contracts are subject to negotiation, they are based loosely on PacifiCorp's published avoided cost rates, which are in the neighborhood of $50-$60/MWh when averaged over the 20-year contract term.
- Just to the north in Idaho, Idaho Power announced in late 2014 that it had recently entered into avoided cost contracts for 461 MW of utility-scale PV, and that another 885 MW was actively seeking such contracts. Idaho Power's avoided cost contracts feature pricing that varies by time of day and season, but averages out to about $60-70/MWh over the 20-year term.

This recent onslaught of applications for avoided cost contracts has prompted the utilities involved and their state utility regulators to re-evaluate these contracts and the utilities' PURPA requirements. In early 2015, for example, Idaho Power requested that its standard avoided cost contract term be reduced from 20 to just 2 years; regulators subsequently reduced the term to 5 years while they examined the issue, and in August 2015 agreed to impose a 2-year term. Around the same time, regulators in North Carolina rejected a similar utility request to lower the capacity threshold, shorten the contract term, and reduce contract pricing for solar projects. Meanwhile in Utah, PacifiCorp is also pushing back (as developers with Idaho projects that were stranded by the reduction in contract term are now looking south to PacifiCorp as a more-viable market), and would like to reduce solar compensation via a reduction in the capacity credit assigned to solar within the avoided cost calculation. How these various proceedings play out could significantly affect the future of utility-scale solar within these states. In the near term, however, grandfathered contracts will fuel a frenzy of new PV project construction in these emerging states through 2016.

For each of the contracts in the sample,[44] we have collected the contractually locked-in PPA price data over the full term of the PPA,[45] and have accounted for any escalation rates and/or time-of-delivery ("TOD") pricing factors employed.[46] The PPA prices presented in this section, therefore, reflect the full revenue available to (and presumably in many cases, the minimum

[44] In general, each PPA corresponds to a different project, though in some cases a single project sells power to more than one utility under separate PPAs, in which case two or more PPAs may be tied to a single project.
[45] The minimum PPA term in the sample is 10 years (though the two 10-year contracts in the sample are effectively 4-year "bridge" PPAs with a California municipality, whereby the buyer takes 100% of the output for the first four years and then, once a long-term contract with an investor-owned utility begins in 2019, just 1% of the output in the last six years). The maximum is 34 years, the mean is 22.8 years, the median is 25 years, and the capacity-weighted average is 23.4 years.
[46] In cases where PPA price escalation rates are tied to inflation, the EIA's projection of the U.S. GDP deflator from *Annual Energy Outlook 2015* is used to determine expected escalation rates. For contracts that use time-of-delivery pricing and have at least one year of operating history, each project's average historical generation profile is assumed to be replicated into the future. For those projects with less than a full year of operating history, the generation profiles of similar (and ideally nearby) projects are used as a proxy until sufficient operating experience is available.

amount of revenue required by[47]) these projects over the life of the contract – at least on a post-incentive basis. In other words, these PPA prices do reflect the receipt of federal tax incentives (e.g., the 30% investment tax credit or cash grant, accelerated tax depreciation) [48] and state incentives (e.g., grants, production incentives, various tax credits), and would be higher if not for these incentives.[49,50] As such, the levelized PPA prices presented in this section should *not* be equated with a project's unsubsidized levelized cost of energy ("LCOE").

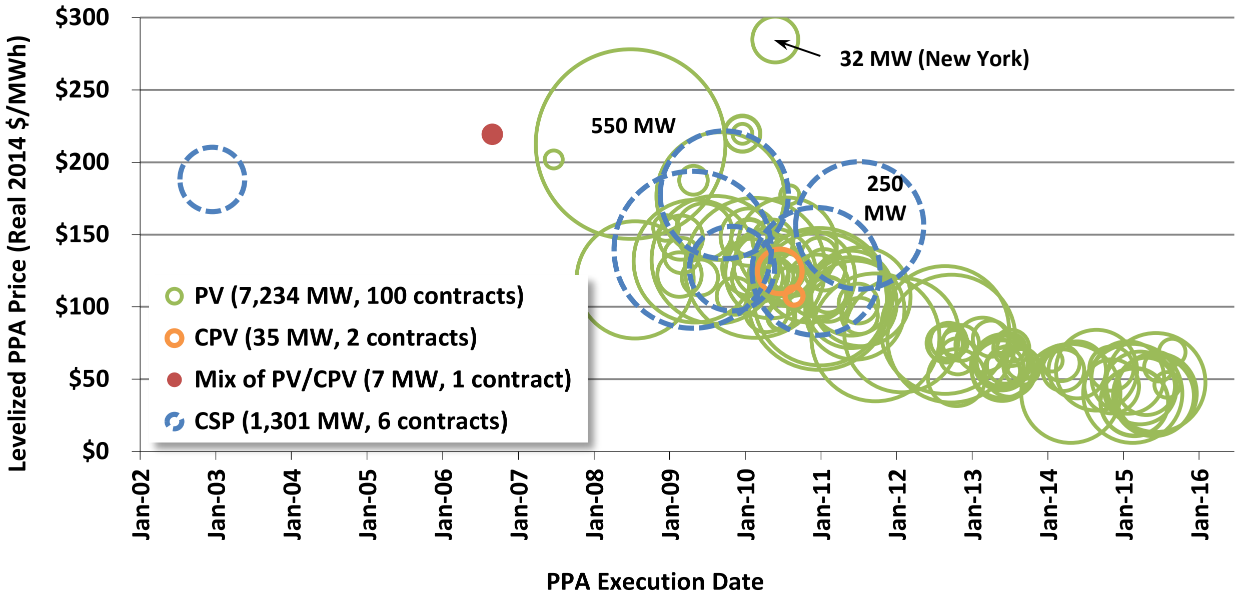


Figure 15. Levelized PPA Prices by Technology, Contract Size, and PPA Execution Date

[47] In a competitive "cost-plus" pricing environment – where the PPA price is just sufficient to recoup initial capital costs, cover ongoing operating costs, and provide a normal rate of return – PPA prices will represent the minimum amount of revenue required by a project. In contrast, "value-based" pricing occurs when the project developer or owner is able to negotiate a higher-than-necessary PPA price that nevertheless still provides value to the buyer.

[48] In addition to the other federal incentives listed, eleven projects within the sample also received DOE loan guarantees through the Section 1705 program. In all eleven cases, however, the projects had already executed PPAs by the date on which the loan guarantee was awarded, suggesting that the guarantee didn't affect the PPA price.

[49] For example, taking a simplistic view (i.e., not considering financing effects), the average PPA price could be as much as 50% higher (i.e., 30%/(1 minus the federal tax rate)) if there were no federal investment tax credit ("ITC"). Without the ITC, however, the resulting increase in PPA prices would be limited by the fact that sponsors with tax appetite could then leverage up their projects more heavily with cheap debt, while sponsors without tax appetite would be able to forego expensive third-party tax equity in favor of cheaper forms of capital, like debt. Because of these financing shifts, the PPA price would not increase by 50%, but rather more like 35-40% in the case of a sponsor with tax appetite, and by roughly 20% in the case of a sponsor without tax appetite that currently relies on third-party tax equity to monetize the ITC (Bolinger 2014).

[50] Though there is too much variety in state-level incentives to systematically quantify their effect on PPA prices here, one example is New Mexico's refundable Production Tax Credit, which provides a credit of varying amounts per MWh (averaging $27/MWh) of solar electricity produced over a project's first ten years. One PPA for a utility-scale PV project in New Mexico allows for two different PPA prices – one that is $43.50/MWh higher than the other, and that goes into effect only if the project does not qualify for the New Mexico PTC. Based on New Mexico's top corporate tax rate of 7.6%, a $43.50/MWh price increase due to loss of New Mexico's PTC seems excessive (a more appropriate 20-year adjustment would seemingly have been roughly half that amount), but nevertheless, this is one tangible example of how state incentives can reduce PPA prices.

Figure 15 shows trends in the levelized (using a 7% real discount rate) PPA prices from the entire sample over time. Each bubble in Figure 15 represents a single PPA, with the area of the bubble corresponding to the size of the contract in MW and the placement of the bubble reflecting both the levelized PPA price (along the vertical y-axis) and the date on the which the PPA was executed (along the horizontal x-axis).[51] Different solar technologies (e.g., PV versus CPV versus CSP) are denoted by different colors and patterns.

Figure 15 provides a number of insights:

- PPA pricing has, in general, declined over time, to the point where recent PPAs have been priced as aggressively as $40/MWh levelized (in real, 2014 dollars), or even lower. In the Southwest (where these low-priced projects are primarily located), pricing this low is, in some cases, competitive with in-region wind power.[52] This is particularly the case when considering solar's on-peak generation profile, which can provide ~$25/MWh of TOD value relative to wind.[53]

- Although at first glance there does not seem to be a significant difference in the PPA prices required by different solar technologies, it is notable that all of the recent PPAs in the sample employ PV technology. Back in 2002 when the Nevada Solar One (CSP) PPA was executed, PV was too expensive to compete at the wholesale level, but by 2009-2011 when the other five CSP PPAs in the sample were executed, PV pricing had closed the gap. Since then, virtually all new contracts have employed PV technology, while a number of previously-executed CSP contracts have been either canceled or converted to PV technology. CPV was seemingly competitive back in 2010 when the two contracts in the sample were executed, but lack of any new contracts since then (at least within the sample) prevents a more-recent comparison – and is perhaps telling in its own right.[54]

- Smaller projects (e.g., in the 20-50 MW range) feature PPA prices that are just as competitive as larger projects. Very large projects often face greater development challenges than smaller projects, including heightened environmental sensitivities and more-stringent permitting requirements, as well as greater interconnection and transmission hurdles. Once a project grows beyond a certain size, the costs of overcoming these incremental challenges may outweigh any benefits from economies of scale in terms of the effect on the PPA price.

[51] Because PPA prices reflect market expectations at the time a PPA is executed – which could be two years or more in advance of when the project achieves commercial operation – the PPA execution date is more relevant than the commercial operation date when analyzing PPA prices.
[52] See, for example, the text box in Bolinger and Weaver (2013) that compares the economics of the co-located Macho Springs wind and solar projects.
[53] For further explanation, see the text box titled *Estimating PV's TOD Value* in the 2013 edition of this report (Bolinger and Weaver 2014). Also note that the levelized PPA prices shown in Figure 15 (and throughout this chapter) already incorporate all applicable TOD factors. Not all PPAs, however, use explicit TOD factors, though in those instances where they are not used, PV's on-peak generation profile still presumably provides higher *implicit* value (compared to wind) to the buyer.
[54] That said, SunPower has been quietly rolling out its new low-concentration (7 suns) C7 CPV technology, with a 1 MW_{AC} pilot project at Arizona State University (online in early 2013); a contract with Apple for the 20 MW_{AC} Fort Churchill Solar Project (scheduled to come online in 2015) to power its data center near Reno, NV; and a sale of technology to a project in China. At present, no cost or price information is available for these projects.

- Not surprisingly, the highest-priced contract in the sample comes from Long Island, which does not enjoy the abundant sunshine of the Southwest (where most of our sample is located – 93% of the total capacity within the PPA sample is located in CA, NV, AZ, or NM), and where wholesale power prices are high due to transmission constraints.

Not all of the projects behind the contracts shown in Figure 15 are fully (or even partially) operational, though all of them are still in play (i.e., the sample does not include PPAs that have been terminated). Figure 16 shows the same data as Figure 15, but broken out according to whether or not a project has begun to deliver power.[55] Understandably, most of the more-recently signed PPAs in the sample pertain to projects that are still in development or under construction, and have not yet begun to deliver electricity under the terms of the PPA. Given that many of these same PPAs are also the lowest-priced contracts in the sample, it remains to be seen whether all of these projects can be profitably built and operated under the aggressive PPA price terms shown here.[56] That said, a recent and related modeling analysis (Bolinger, Weaver, and Zuboy 2015) finds that today's aggressive PPA prices can indeed pencil out using modeling assumptions that are based on best-in-class PV data presented in other sections of this report. Moreover, as described in the text box on the next page, a survey of recent solicitation responses reveals a deep field of projects bidding into solicitations at these low prices – i.e., the recent low prices shown in Figure 15 and Figure 16 do not appear to be one-off anomalies.

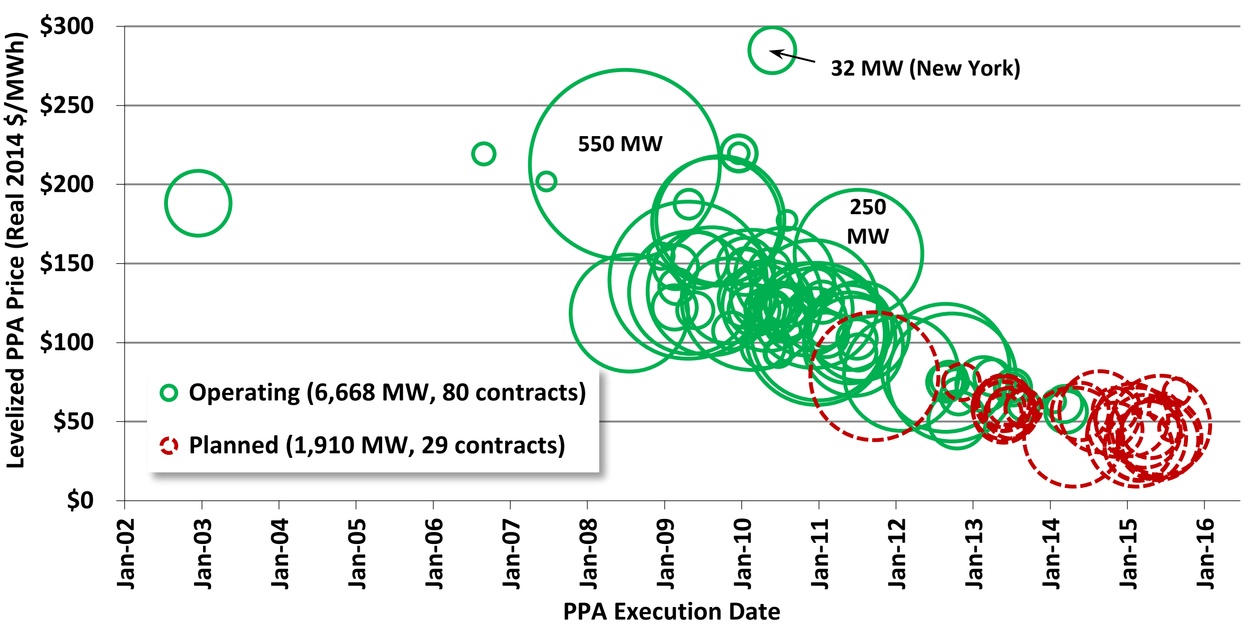


Figure 16. Levelized PPA Prices by Operational Status and PPA Execution Date

[55] If a project had begun to deliver power by August 2015 – even if not yet fully operational or built out to its contractual size – it is characterized as "operating" in Figure 16. Only those projects that were still in development or were under construction but not yet delivering power are characterized as "planned."

[56] There is a history of solar project and PPA cancellations in California, though in many cases these have involved projects using less-mature technologies (e.g., Stirling dish engines, compact linear Fresnel reflectors, and power towers). For PV projects, price revisions are perhaps a more likely risk – e.g., if the solar trade dispute with China were to harm existing module supply contracts.

Solicitation Responses Reveal Deep Market at Low Prices

Although our sample of low-priced solar PPAs signed in 2014 and so far in 2015 is relatively small (21 contracts totaling 1.33 GW), a survey of developer responses to several recent utility solicitations suggests that there is considerable depth in the market at these low price levels, at least in the Southwest. For example:

- Southwestern Public Service's 2014 request for proposals ("RFP") for 200 MW of solar received 53 transmission-level project bids totaling 4,040 MW and 59 distribution-level project bids totaling 1,210 MW (for a total of 5,250 MW – more than 26 times the 200 MW target). Of the transmission-level proposals, 2,718 MW bid levelized prices ranging from $40-$50/MWh, while another 1,182 were priced between $50-$60/MWh. Of the distribution-level proposals (typically featuring smaller projects), 240 MW bid levelized prices ranging from $40-$50/MWh while 600 MW were priced from $50-60/MWh. Many of these projects are located in New Mexico, which provides a 10-year state production tax credit that helps developers to lower PPA prices (though not all bidders assumed full receipt of the state PTC).
- In late 2014 and early 2015, NV Energy issued two 100 MW renewable energy RFPs; bidders in the 2014 RFP were allowed to re-bid into the 2015 RFP, and two 100 MW PV projects were ultimately selected. One of the winning projects is priced at $46/MWh flat over 20 years (i.e., $38.6/MWh levelized in real 2014 dollars), while the other starts at $38.70/MWh (nominal) and escalates at 3%/year over 20 years (i.e., $40.1/MWh levelized in real 2014 dollars). Of the 2,537 MW of renewable resources that bid (or re-bid) into the 2015 RFP, more than 90% were solar, while wind and geothermal accounted for just 8% and 2%, respectively. Though no pricing information is available for the non-winning bids, several hundred additional MW of shortlisted capacity were reportedly bid at prices very similar to the winning bids. Moreover, NV Energy noted that the solar bids were priced lower than the wind or geothermal bids, and also better matched its load profile.
- Austin Energy's 2015 RFP for 600 MW of solar received 149 unique proposals totaling 7,976 MW (more than 13 times coverage) from 33 different bidders. Almost 1,300 MW were reportedly bid at levelized prices of $45/MWh or less.

Taken as a whole, these responses suggest that there is a significant amount of utility-scale PV capacity capable (at least with the 30% ITC) of selling electricity at very low prices in the Southwest. Moreover, at these low price levels, solar can compete head on with wind power in terms of both price and generation profile (for more on comparisons of solar and wind in the Southwest, see the text box titled "Estimating PV's TOD Value" in the 2013 edition of this report, or the text box on the co-located Macho Springs wind and solar projects in the 2012 edition).

More than two-thirds of the PV contracts in the sample feature pricing that does not escalate in nominal dollars over the life of the contract – which means that pricing actually *declines* over time in real dollar terms. Figure 17 illustrates this decline by plotting over time, in real 2014 dollars, the generation-weighted average price among *all* PPAs executed within a given year (i.e., including both escalating and non-escalating contracts).

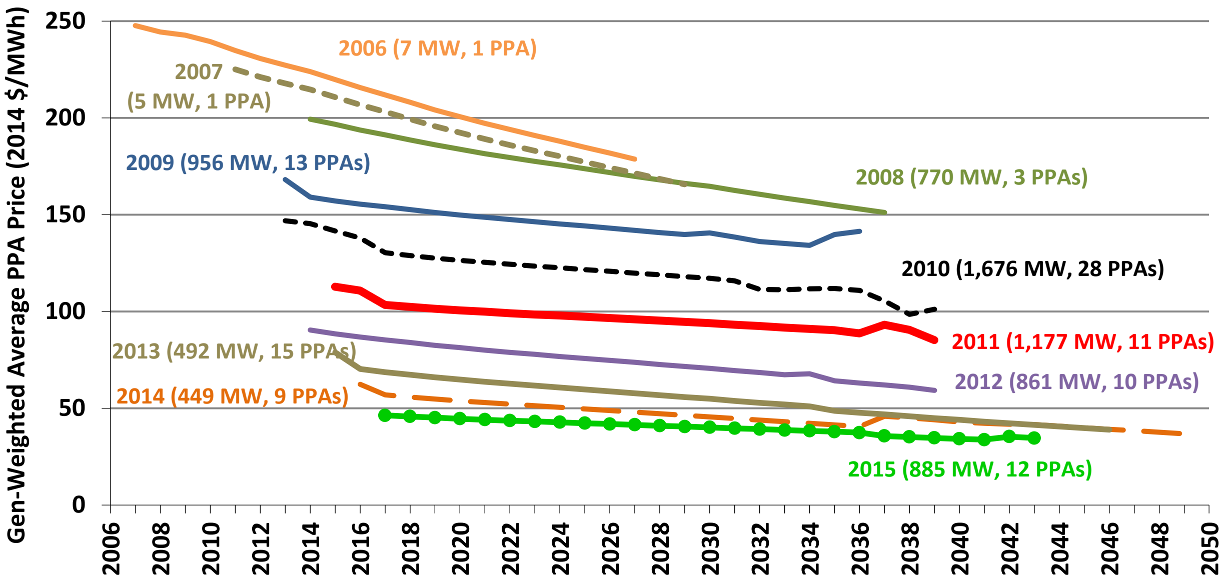


Figure 17. Generation-Weighted Average PV PPA Prices Over Time by Contract Vintage

By offering flat or even declining prices in real dollar terms over long periods of time, solar (and wind) power can provide a long-term hedge against the risk of rising fossil fuel prices (Bolinger 2013). Figure 18 illustrates this potential value by plotting the future stream of average PV PPA prices from contracts executed in 2014 and 2015 (i.e., the same two lines as the 2014 and 2015 vintage PPA lines in Figure 17 above) against a range of projections of *just the fuel costs* of natural gas-fired generation.[57] Focusing on the 2015 PPA vintage in particular, average PPA prices from PV contracts executed in 2015 start out higher than the range of fuel cost projections in 2017, but decline (in real 2014 $/MWh terms) over time and eventually fall below the reference case gas price projection by 2021 (and below the *entire range* of gas price projections by 2037). On a levelized basis from 2017 through 2040, the 2015-vintage PV PPA prices come to $42.1/MWh (real 2014 dollars) compared to $48.1/MWh for the reference case fuel price projection, suggesting that PV may be able to compete with even just the fuel costs of *existing* gas-fired generators (i.e., not even accounting for the recovery of fixed capital costs incurred by *new* gas-fired generators).

Moreover, it is important to recognize that the PV PPA prices have been contractually locked in, whereas the fuel cost projections to which they are compared are highly uncertain – actual fuel costs could end up being either lower or potentially much higher. Either way, as evidenced by the widening range of fuel cost projections over time, it becomes increasingly difficult to forecast fuel costs with any accuracy as the term of the forecast increases.

[57] The national average fuel cost projections come from the Energy Information Administration's *Annual Energy Outlook 2015* publication, and increase from around $4.67/MMBtu in 2015 to $8.83/MMBtu (both in 2014 dollars) in 2040 in the reference case. The range around the reference case is bounded by the high oil and gas resource case on the low end, and the greater of the high oil price or high economic growth cases on the high end (since AEO 2015 does not include a low oil and gas resource case), and ranges from $4.98/MMBtu to $10.75/MMBtu (again, all in 2014 dollars) in 2040. These fuel prices are converted from $/MMBtu into $/MWh using the heat rates implied by the modeling output (these start at roughly 8,100 Btu/kWh and gradually decline to around 7,200 Btu/kWh by 2040).

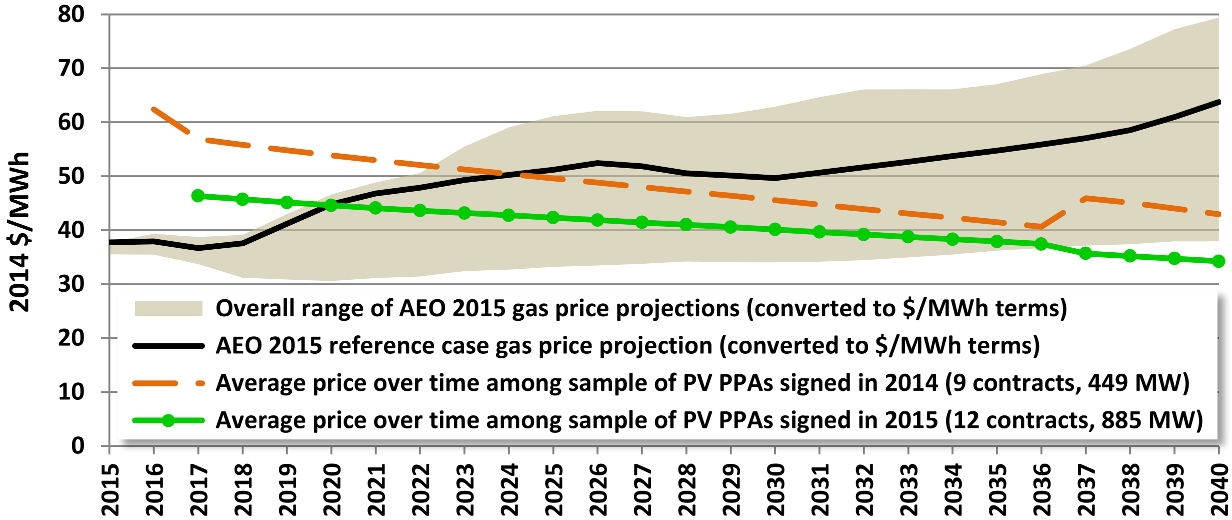


Figure 18. Average PV PPA Prices and Natural Gas Fuel Cost Projections Over Time

In addition to the declining real prices over time within each PPA vintage shown in Figure 17 and Figure 18, the steady march downward across vintages is also evident in Figure 17, demonstrating substantial reductions in pricing by PPA execution date.[58] To provide a clearer look at the time trend, the blue-shaded columns in Figure 19 simply levelize the price streams shown in Figure 17. Based on this sample, levelized real PPA prices for utility-scale PV projects consistently fell by almost $25/MWh per year on average from 2006 through 2013, with a smaller price decline of ~$10/MWh evident in the 2014 and 2015 samples. With levelized real PPA prices now below $50/MWh on average (based on the combined 2014/2015 sample), future price declines are likely to be much smaller than in the past.

Figure 19 also shows that the overall spread in pricing has narrowed over time – e.g., the 2013-2015 samples show a tighter range of levelized prices than do the 2009-2011 samples – suggestive of an increasingly mature and transparent market. Moreover, this narrowing has occurred despite the fact that the geographic scope of the market (and sample) has broadened with time. Although the PPAs in our sample are still heavily concentrated in the Southwest, the market is beginning to expand to new parts of the country – notably the Southeast (see the text

[58] This strong time trend complicates more-refined analysis of other variables examined in earlier chapters, such as resource strength (though again, 93% of the capacity in the PPA price sample is in the high-insolation states of CA, NV, AZ, and NM), tracking versus fixed-tilt, and c-Si versus thin-film. To try and control for the influence of time, one could potentially analyze these variables within a single PPA vintage, but doing so might divide the sample to the point where sample size is too small to reliably discern any differences. Furthermore, it is not clear that some of these variables should even have much of an effect on PPA prices. For example, several of the PV contracts in the sample note uncertainty over whether or not tracking systems will be used, or whether c-Si or thin-film modules will be deployed. Yet the executed PPA price is the same regardless of the ultimate project configuration, suggesting that the choice of tracking versus fixed-tilt or c-Si versus thin-film is (at least in these cases) not a critical determinant of PPA pricing. This makes sense when one considers that tracking systems, for example, add up-front costs to the project (see Chapter 3) that are recouped over time through greater energy yield (see Chapter 5), thereby potentially leaving the net effect on PPA prices largely a wash. In support of this theory, the Public Service Company of New Mexico estimated (based on a review of 216 solar responses to its 2012 Renewable RFP) that the average PPA price benefit of single-axis tracking was just $3/MWh, or less than 4% of a levelized PPA price in the mid-$70/MWh range (O'Connell 2013).

box below) but also states like Utah and Idaho where utilities have had attractive avoided cost rates (see earlier text box on “avoided cost” markets). For example, the 2015 PPA price sample includes contracts not only in the usual Southwestern states, but also in Florida, Arkansas, and Alabama – and at prices not too far above those seen in the Southwest.

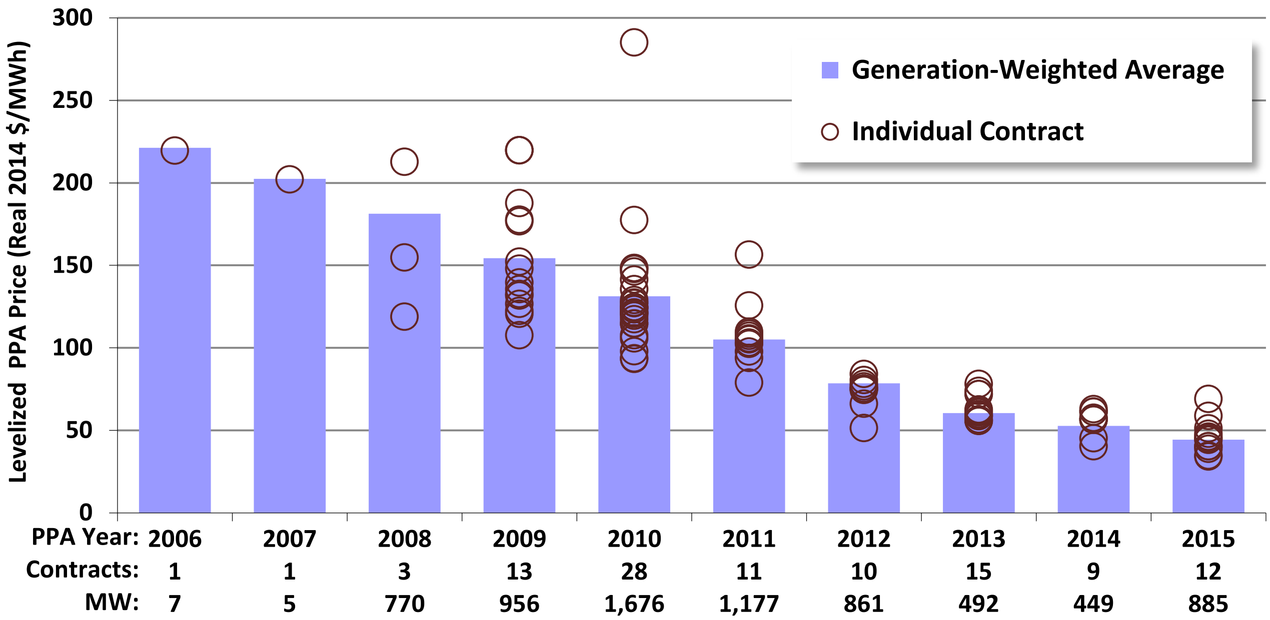


Figure 19. Levelized PV PPA Prices by Contract Vintage

Trend to Watch: The Rise of the South

Although the sample of PPA prices analyzed in this chapter is highly concentrated in the southwestern United States – i.e., 97% of the 8.7 GW of capacity in the sample is located in CA (68%), NV (11%), AZ (11%), TX (4%), NM (3%), and CO (1%) – there have been a number of notable announcements over the past year about new utility-scale solar PPAs being signed at competitive prices in several *southeastern* states that have not previously seen much development. The following non-exhaustive list of new contracts (only three of which are currently included in our PPA price sample, due to lack of sufficient information on the others) illustrates this expansion of the market to the Southeast:

- In October 2014, Georgia Power announced long-term PPAs with four “smaller” PV projects totaling 76.5 MW and six “larger” projects totaling 439 MW. Although pricing for individual projects has not been disclosed, the average PPA price among the “smaller” projects is reportedly $65/MWh.
- In February 2015, the Tennessee Valley Authority announced that it had signed a 20-year PPA with an 80 MW PV project in Alabama at a price of $61/MWh.
- In April 2015, NextEra and Entergy Arkansas announced a PPA for the 81 MW Stuttgart Solar Project in Arkansas; the price is reportedly just north of $50/MWh.
- Highlighting yet another notable trend towards direct corporate purchases of renewable power, in June 2015, Community Energy and Amazon Web Services announced a PPA for an 80 MW PV project in Virginia (pricing was not disclosed).
- In July 2015, the Orlando (Florida) Utilities Commission announced a 20-year PPA with a 13 MW PV project priced at $70/MWh, which is less than half the $194/MWh it is paying for a similar 5.5 MW_{AC} project that came online in late 2011.

This trend – also evident in regional interconnection queues, as shown later in Figure 20 – is all the more notable because the Southeast has historically not seen much renewable energy development at all (other than in North Carolina, which has had an active solar market for a number of years, primarily featuring “avoided cost” PURPA contracts for projects of 5 MW or less that fall below our utility-scale size threshold), due in part to fewer state-level policies like renewable portfolio standards, as well as wind resource constraints. For example, unlike in much of the rest of the country, wind power has yet to gain much of a foothold in the Southeast – and may find it hard to compete with solar at the price levels evident in some of these solar contracts.

7. Conclusions and Future Outlook

Other than the SEGS I-IX parabolic trough CSP projects built in the 1980s, virtually no utility-scale PV, CPV, or CSP projects existed in the United States prior to 2007. By 2012 – just five years later – utility-scale had become the largest sector of the overall PV market in the United States, a distinction that was repeated in 2013 and 2014 and that is expected to continue for at least the next few years. Over this same short period, CSP also experienced a renaissance in the United States, with a number of large new parabolic trough and power tower systems – some including storage – either achieving commercial operation or entering the commissioning phase. Although the operating history of many these newer PV, CPV, and CSP projects is still very limited, a critical mass of data nevertheless enables empirical analysis of this rapidly growing sector of the market.

This third edition of LBNL's annual *Utility-Scale Solar* series paints a picture of an increasingly competitive utility-scale PV sector, with installed prices having declined significantly since 2007-2009 (but perhaps showing signs of slowing), relatively modest O&M costs, solid performance with improving capacity factors, and record-low levelized PPA prices of around $40/MWh in some cases and under $50/MWh on average (again, with the steady decline over the years perhaps showing signs of slowing). Meanwhile, the other two utility-scale solar technologies – CPV and CSP – have also made strides in recent years, but are finding it difficult to compete in the United States with increasingly low-cost PV.[59]

Looking ahead, the amount of utility-scale solar capacity in the development pipeline suggests continued momentum and a significant expansion of the industry – both in terms of volume and geographic distribution – over the next few years. Specifically, Figure 20 shows the amount of solar power (and, in the inset, other resources) working its way through 35 different interconnection queues administered by independent system operators ("ISOs"), regional transmission organizations ("RTOs"), and utilities across the country as of the end of 2014.[60]

These data should be interpreted with caution: although placing a project in the interconnection queue is a necessary step in project development, being in the queue does not guarantee that a project will actually be built.[61] That said, efforts have been made by the FERC, ISOs, RTOs,

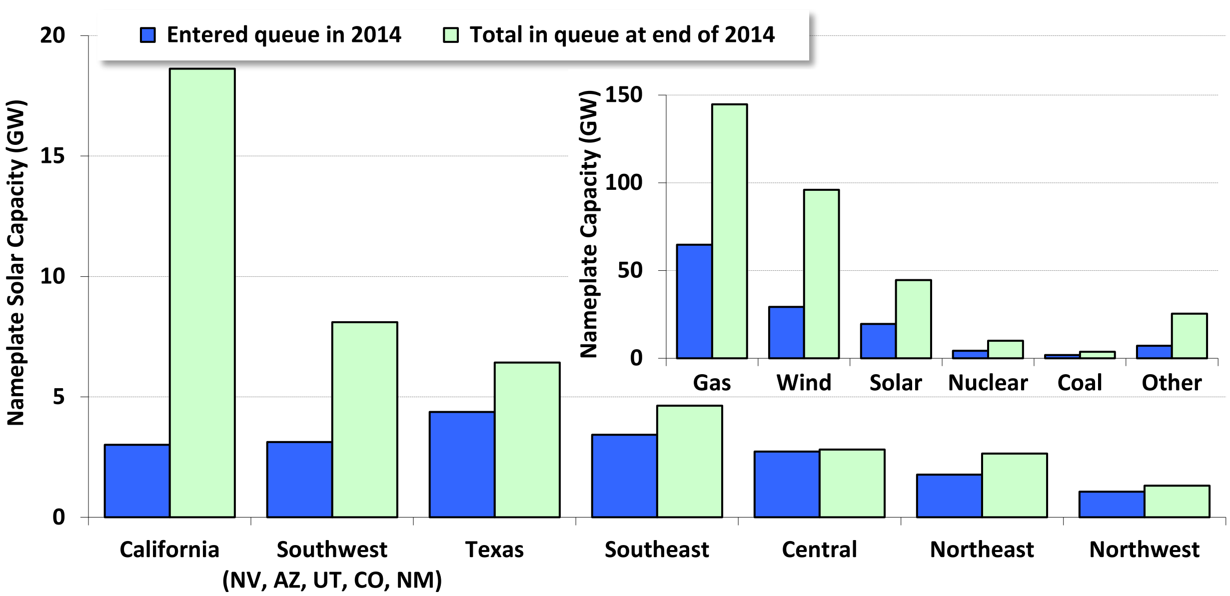
[59] Avian mortality has also emerged as an unexpected potential challenge to power tower technology in particular, but also to large PV projects that, from a distance, can reportedly resemble bodies of water and attract migrating waterfowl that are injured or killed while attempting to land in the solar field.

[60] The queues surveyed include the California ISO, Los Angeles Department of Water and Power, Electric Reliability Council of Texas (ERCOT), Western Area Power Administration, Salt River Project, PJM Interconnection, Arizona Public Service, Southern Company, NV Energy, PacifiCorp, Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), Duke/Progress Energy, Public Service Company of Colorado, Public Service Company of New Mexico, and 20 other queues with lesser amounts of solar. To provide a sense of sample size and coverage, the ISOs, RTOs, and utilities whose queues are included here have an aggregated non-coincident (balancing authority) peak demand of about 86% of the U.S. total. Figure 20 only includes projects that were active in the queue at the end of 2014 but that had not yet been built; suspended projects are not included.

[61] It is also worth noting that while most of the solar projects in these queues are probably utility-scale in nature, the data are not uniformly (or even commonly) consistent with the definition of "utility-scale" adopted in this report. For example, some queues are posted only to comply with the Large Generator Interconnection Procedures in FERC Order 2003 that apply to projects larger than 20 MW, and so presumably miss smaller projects in the 5-20 MW

and utilities to reduce the number of speculative projects that have, in recent years, clogged these queues.

Even with this important caveat, the amount of solar capacity in the nation's interconnection queues still provides at least some indication of the amount of planned development. At the end of 2014, there were 44.6 GW of solar power capacity (of any type – e.g., PV, CPV, or CSP) within the interconnection queues reviewed for this report – ***more than five times the installed utility-scale solar power capacity in our entire project population at that time.*** These 44.6 GW (19.5 GW of which first entered the queues in 2014) represented nearly 14% of all generating capacity within these selected queues at the time, in third place behind natural gas at 45% and wind at 30% (see Figure 20 inset). The end-of-2014 solar total is also more than 5 GW higher than the 39.5 GW of solar that were in the queues at the end of 2013, suggesting that the solar pipeline has been more than replenished over the past year, despite the record amount of new solar capacity that came online (and therefore exited these queues) in 2014, as well as the impending reversion of the 30% ITC to 10% scheduled for the end of 2016.



Source: Exeter Associates review of interconnection queue data

Figure 20. Solar and Other Resource Capacity in 35 Selected Interconnection Queues

The larger graph in Figure 20 breaks out the solar capacity by state or region, to provide a sense of where in the United States this pipeline resides. Perhaps not surprisingly (given the map of solar resource and project location shown in Figure 3, earlier), 60% of the total solar capacity in the queues at the end of 2014 is within California (42%) and the Southwest region (18%). This combined 60% is down from 80% at the end of 2013, however, and is yet another indication that the utility-scale solar market is spreading to new states and regions beyond California and the Southwest. For example, 14% of the solar capacity in the queues at the end of 2014 resides in Texas, followed by 10% in the Southeast and 6% in each of the Central and Northeast regions.

range. Other queues include solar projects of less than 5 MW (or even less than 1 MW) that may be more commercial than utility-scale in nature. It is difficult to estimate how these two opposing influences net out.

Moreover, in terms of *new* solar capacity entering the queue in 2014, Texas ranked first (22%), followed by the Southeast (18%), Southwest (16%), California (15%), and Central (14%) regions. As the competitiveness of solar continues to improve, the market is spreading to still-untapped parts of the country.

Though not all of the 44.6 GW of planned solar projects represented within Figure 20 will ultimately be built, presumably most of what is built will come online prior to 2017, given the scheduled reversion of the 30% ITC to 10% at the end of 2016. To that end, as of the end of 2014, GTM/SEIA (2015) projected a utility-scale solar pipeline of 26.7 GW in 2015-2016 (9.1 GW in 2015 and 17.6 GW in 2016), 14.1 GW of which was already contracted (6 GW in 2015 and 8.1 GW in 2016). Even if only this 26.7 GW – or, for that matter, even just the contracted 14.1 GW portion – came online prior to 2017, it would still mean an unprecedented amount of new solar construction in 2015 and 2016. Of course, accompanying all of this new capacity will be substantial amounts of new operational data, which we will collect and analyze in future editions of this report.

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Data Sources

Much of the analysis in this report is based on primary data, the sources of which are listed below (along with some general secondary sources), broken out by data set:

Technology Trends (Chapter 2):

Form EIA-860, FERC Form 556, state regulatory filings, the National Renewable Energy Laboratory ("NREL"), the Solar Energy Industries Association ("SEIA"), trade press articles

Installed Prices (Chapter 3):

Section 1603 grant data from the U.S. Treasury, FERC Form 1, data from applicable state rebate and incentive programs, state regulatory filings, company financial filings, interviews with developers and owners, trade press articles, and data previously gathered by NREL

O&M Costs (Chapter 4):

FERC Form 1 and state regulatory filings (empirical data)

Capacity Factors (Chapter 5):

FERC Electronic Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings

PPA Prices (Chapter 6):

FERC Electronic Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings, company financial filings, trade press articles

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Renewable Energy as a Hedge Against Fuel Price Fluctuation

How to Capture the Benefits

Commission for Environmental Cooperation

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This background paper was written by Dan Lieberman and Siobhan Doherty from the Center for Resource Solutions for the Secretariat of the Commission for Environmental Cooperation. The information contained herein does not necessarily reflect the views of the governments of the CEC, or the governments of Canada, Mexico or the United States of America.

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Executive Summary

In a time of fuel price fluctuation, the use of renewable energy may offer, along with environmental benefits, greater stabilization of electricity costs. The pricing volatility of fossil fuels, along with the difficulty of forecasting fossil fuel prices, puts energy customers and providers at risk from fluctuating energy rates. As an alternative, this paper explores the potential for renewable energy to serve as a financial "hedge," reducing exposure to fuel price risk. Renewable energy generation brings with it the price stability benefits of free-fuel generation from emerging technologies such as solar, wind, small hydro, and geothermal sources. Renewable energy costs tend to be stable or decreasing over time, compared to rising or fluctuating costs for fossil fuel. With certain factors in place, it has been demonstrated that renewable energy can be effectively priced at or below the cost of conventional sources.
.
As the paper presents, renewable energy can serve as a financial hedge in two key ways that result in both public and private benefit:

- Since renewable energy resources (with the exception of biomass) do not require purchased fuel, the operating costs over time are highly predictable, as opposed to fossil fuel markets.
- Renewable energy reduces the demand for non-renewable resources, potentially easing prices of fossil fuels.

The paper goes on to detail the practices through which renewable energy can provide hedging solutions for utilities or other load-serving entities at the utility-scale, and can also provide price stability benefits for retail customers who receive price-stable purchasing terms or install renewables on-site. Utilities and electric service providers can tap into the price hedge value of renewables by:

- Basing their evaluation of future natural gas prices not on forecasts but on forward prices.
- Including future regulatory risk as a factor when evaluating non-renewables.
- Including renewable energy in an integrated resources plan analysis or as a critical part of the supply portfolio.
- Buying renewable energy or renewable energy certificates through Contracts for Differences.

Individual electric customers can obtain the price stability benefits of renewable energy by:

- Installing on-site renewable energy generation.
- Buying renewables though a pricing structure that is based on the long-term price of the renewable energy and is not tied to fossil fuel prices.

Section I of the paper presents various data points depicting the volatility and unpredictability in electricity markets, primarily due to wildly fluctuating natural gas prices. The second section describes the price stability benefits of free-fuel renewable energy resources. Section III ties together the preceding sections by elaborating the concept of renewable energy serving as a financial hedge. Finally, the last section further examines renewable energy's price-stabilizing potential through the following case studies: the California Renewable Portfolio Standard, the Solar Services Model of SunEdison, Austin Energy's Stable Rate Green Tariff, the Public Service Company of Colorado 2003 Least-Cost Resource Plan, and the City of Calgary's Contract for Differences.

Introduction

Energy consumers – residential and non-residential alike – are concerned about the volatility of energy prices. Enter the term "volatile energy prices" into the Google website and you receive over a million hits. Similarly, public opinion polls show that energy users are in favor of building more renewable resources. But how can individual energy customers and their providers tap into this opportunity to encourage more renewables and provide greater stability to their electricity prices? And how can regulators and policymakers encourage this to happen? Those questions are addressed in this paper.

This paper demonstrates the benefits of renewable energy as a hedge against electricity market fuel price fluctuation. The paper considers how regulators and electricity customers may address this opportunity either as a socialized cost/benefit scenario (by including renewable energy in the rate base), on an individual customer basis (through green pricing options that convey price stability benefits, via on-site installation of renewable energy generation technology under different business models, and through fuel switching), or through several approaches simultaneously.

Throughout this paper, the term renewable energy generation refers to the "green" or "emerging technologies" such as solar, wind, small hydro, and geothermal sources. The term "hedge" used in this paper uses in the traditional generic meaning, referring to the activity of reducing the exposure to price risk.

I. The Problem of Pricing Volatility

This section of the report provides an overview of available data demonstrating the effects of fossil fuel price volatility on electricity markets and provides a forecast of future prices.[1] It is safe to say that all of North America is dependent upon fossil fuels, and that the pricing volatility of these fuels puts energy customers and providers at risk from fluctuating energy rates.

In 2002, the United States' energy consumption was supplied by 39 percent petroleum, 24 percent natural gas, and 23 percent coal.[2] Similarly, electricity generation in the U.S. in 2005 was sourced by 49.7 percent coal and 18.7 percent natural gas.[3] Therefore, even slight fluctuations in the price of fossil fuels can have wide-reaching impacts.

In Mexico in 2004, 82 percent of electricity generation came from conventional thermal sources (of the thermal feedstock, fuel oil represented 44 percent, natural gas represented 33 percent and coal represented 12 percent), 10 percent came from hydroelectricity, 4 percent came from nuclear power, and 4 percent came from other renewables. However, nearly all private generators operate capacity fired by natural gas. As a result, the general trend in overall feedstock consumption has seen a decline in petroleum-based fuels and a growth in natural gas and coal.[4]

In Canada, 58 percent of electricity generation comes from hydroelectricity, followed by coal (19 percent), nuclear (12 percent), natural gas (6 percent), oil (3 percent), and other renewables (2 percent).[5] Canada and the United States have an extensive electricity trade, and the electricity networks of the two countries are heavily integrated.

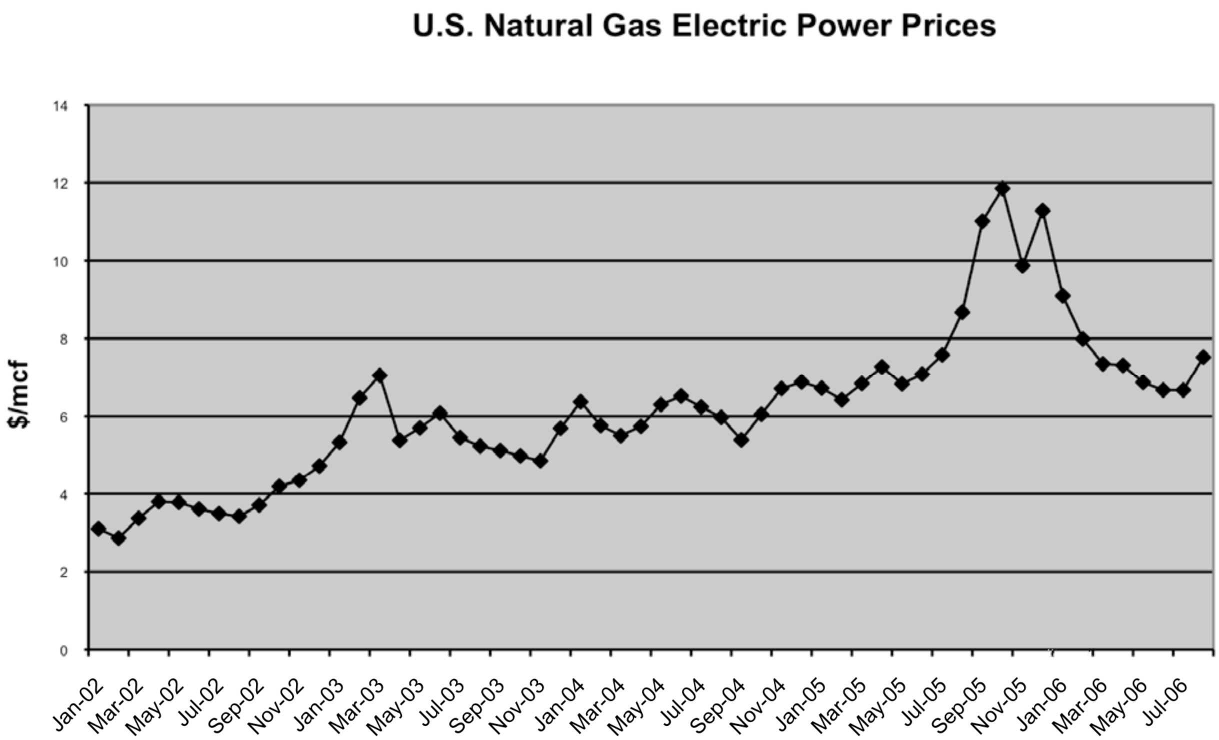
The volatility of natural gas prices has made headlines in recent years. The build-up of natural gas-fired power plants in the last twenty years has increased North America's dependence on natural gas. The combination of tight supplies, high demand, and unpredictable factors, such as weather, results in widely varying price points for natural gas. As we witnessed last year, two hurricanes in the Gulf Coast shut in (reduced available output) over 90 percent of offshore U.S. gulf coast natural gas production, significantly affecting North American natural gas markets and reducing production by 20 percent.[6] Currently, about 19 percent of U.S. electricity generation is fueled by natural gas – up from 14 percent just a decade ago.[7] Dependence on natural gas – and the volatility of natural gas prices – varies regionally and temporally, but on the whole is increasing.

The following set of graphs depicts historical and forecast price data for natural gas and coal. The first graph below shows average annual U.S. natural gas prices for the electricity sector for

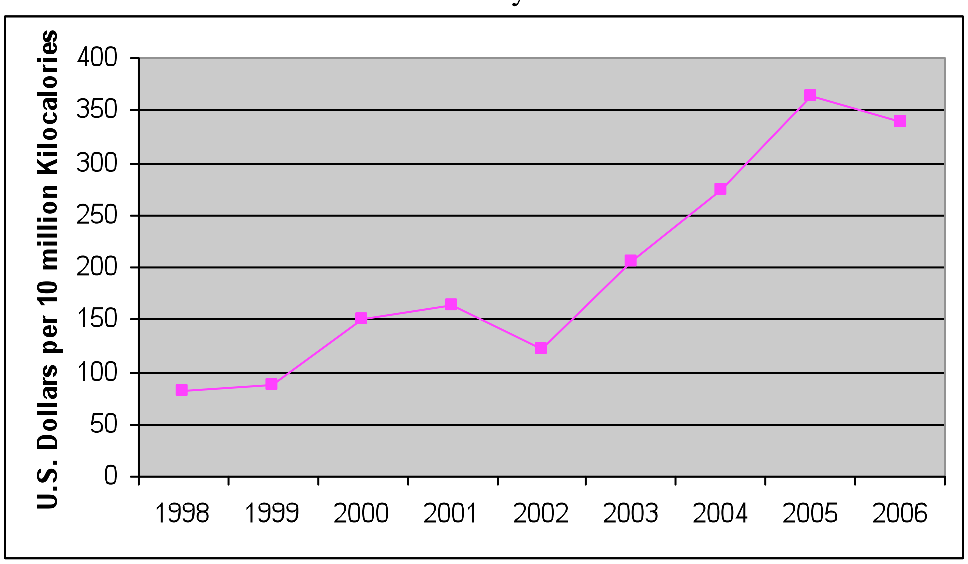
---

[1] Though many of the tables are using U.S. data, the purpose is illustrative with similar volatility effects in other geographic areas dependent upon natural gas as a power plant fuel.
[2] http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/figh1.html
[3] http://www.eia.doe.gov/fuelelectric.html
[4] http://www.eia.doe.gov/emeu/cabs/Mexico/Full.html
[5] http://www.canelect.ca/en/Pdfs/HandBook.pdf
[6] http://www2.nrcan.gc.ca/es/erb/CMFiles/Final_Ex_Sum_ENGLISH206NZG-19012007-3845.pdf
[7] http://www.eia.doe.gov/cneaf/electricity/epa/epat1p1.html

the past five years. Prices in 2002 began around $3 per thousand cubic feet, and then more than doubled to $7 in a year's time. Following a few years of relative stability, prices spiked again in the winter of 2005/06 and then retreated.

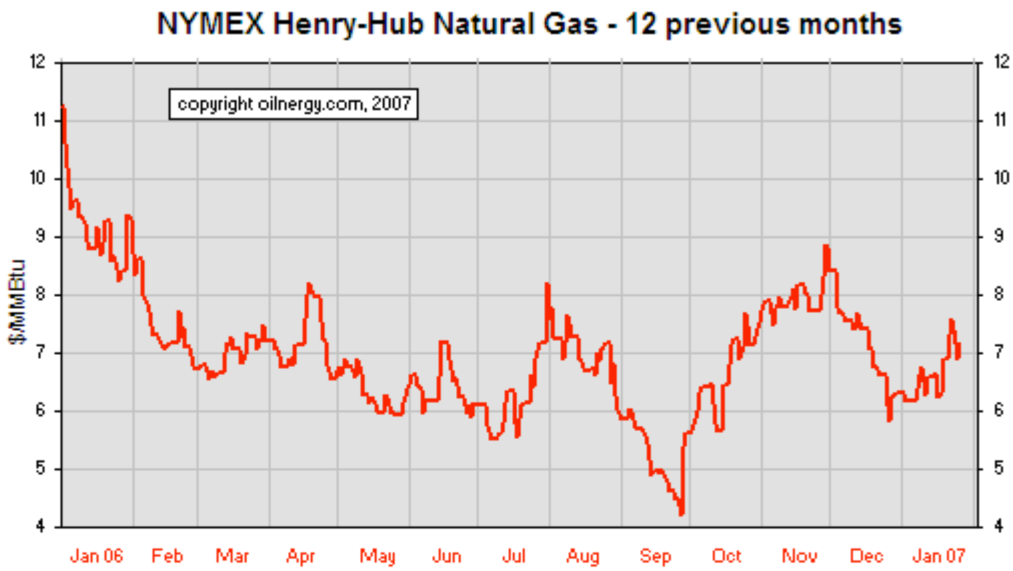


Mexico Natural Gas Prices for Electricity Generation



http://www.eia.doe.gov/emeu/international/ngasprie.html

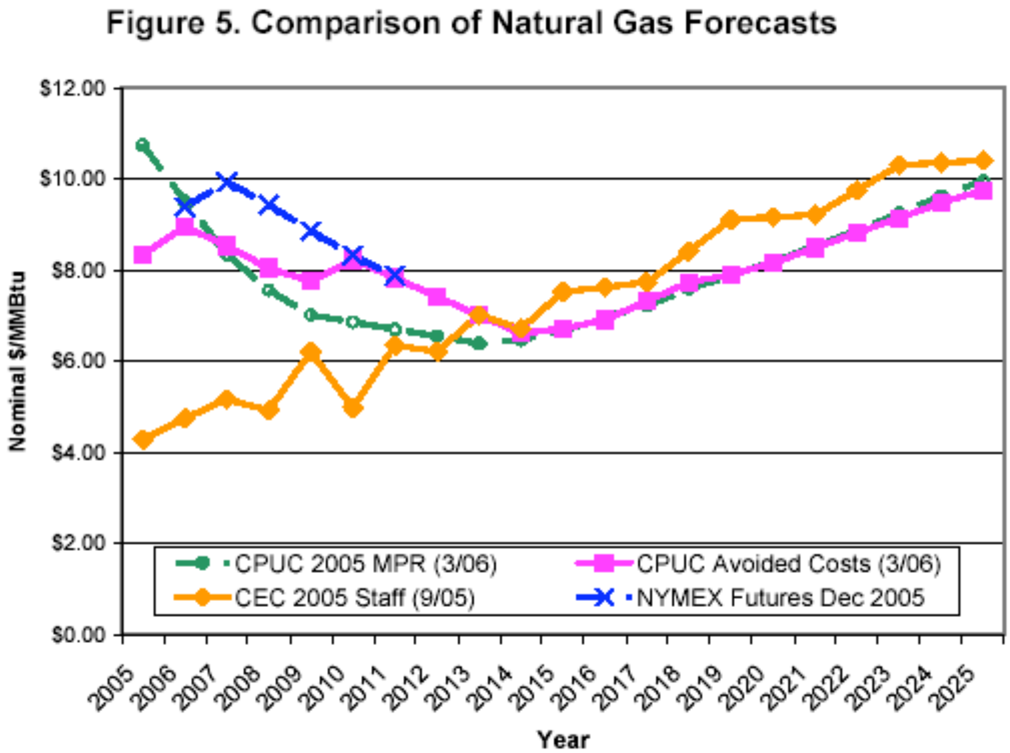
National data and time-aggregated data tend to present a smoother view of what is actually happening in the market. Though the graph above, based on national averages and monthly price points, still demonstrates considerable volatility, we present below a more localized and more granular reporting frequency to demonstrate the actual marketplace volatility. The following graph shows prices for the past year at Henry Hub in Louisiana, the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX).



Source: http://www.oilnergy.com/1gnymex.htm

When estimating the future price of natural gas, experts recommend referencing current NYMEX futures prices. The graph below provides a number of forecasts including NYMEX.[8] An important implication is that government numbers are solely forecasts are made by economists, while the NYMEX futures are financially binding contractual deals. In terms of financial outcomes, there is a significant difference between the two, as the government can/will revise a forecast while a NYMEX contract leaves one party financially liable for the term of the contract. What is most telling about the graph is how divergent the forecasts are, showing the unpredictability of future natural gas prices. Mark Bolinger and Ryan Wiser at Lawrence Berkeley National Laboratory have done an excellent job of comparing the U.S. Department of Energy's Annual Energy Outlook price forecasts of natural gas prices to the actual forward prices as found on NYMEX. Bolinger and Wiser expose the off-target government forecasts, concluding that the Energy Information Administration (EIA) grossly over-projected the price of gas in the late 1980s, and, conversely, has grossly under-projected the price of gas since the mid-1990s. The latest annual summary can be found here:
http://eetd.lbl.gov/ea/emp/reports/53587_memo.pdf

[8] http://eetd.lbl.gov/EA/EMP/reports/61580.pdf



Source: Presentation by Richard McCann at 2006 Integrated Energy Policy Report Midcourse Review Committee workshop, August 22, 2006, *Comparison of Natural Gas Price Forecasts*

Source: http://www.energy.ca.gov/2006publications/CEC-100-2006-001/CEC-100-2006-001-CMF.PDF

Prices for natural gas in Canada have faced similar trends of upward prices and volatility, though slightly less so than in the United States due in part to a strong Canadian dollar, and also the absence of severe weather-related disruptions as experienced in the southern United States. The two key North American natural gas price hubs are the Intra-Alberta Market in Alberta (AECO) and the Henry Hub in Louisiana (NYMEX). Gas purchased on NYMEX typically trades at a $0.50 to $0.80/MMBtu premium relative to AECO.[9]

Mexico has adopted a policy of pricing natural gas based on the Houston price adjusted for transport cost. This is an application of the Little-Mirrlees Rule and results in the market for gas in Mexico having essentially the same character as the Houston market. Pemex behaves as a price taker and inasmuch as Mexico is importing gas from the United States, the price of gas to Mexican consumers reflects the marginal cost of transport to Mexico.[10]

Coal, despite its reputation as the stable workhorse of the electricity industry, has not been immune to pricing volatility in recent years. While the national average price for coal may seem to be relatively stable over time, that is not the case when coal prices are given a closer look.

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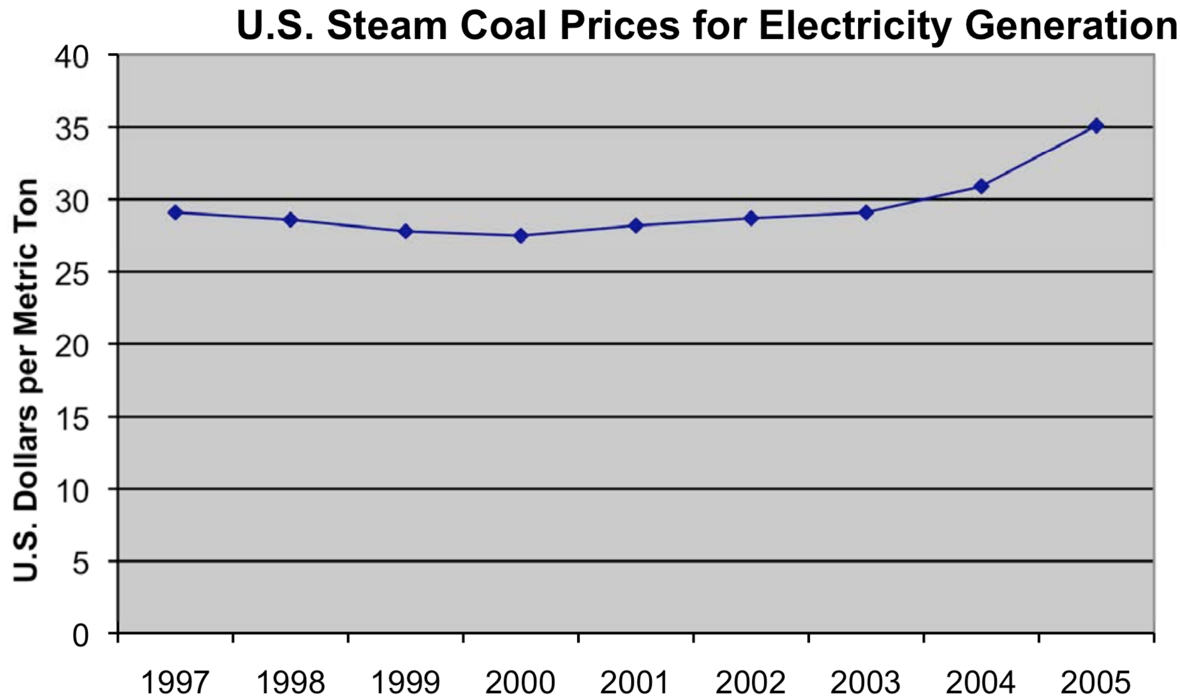
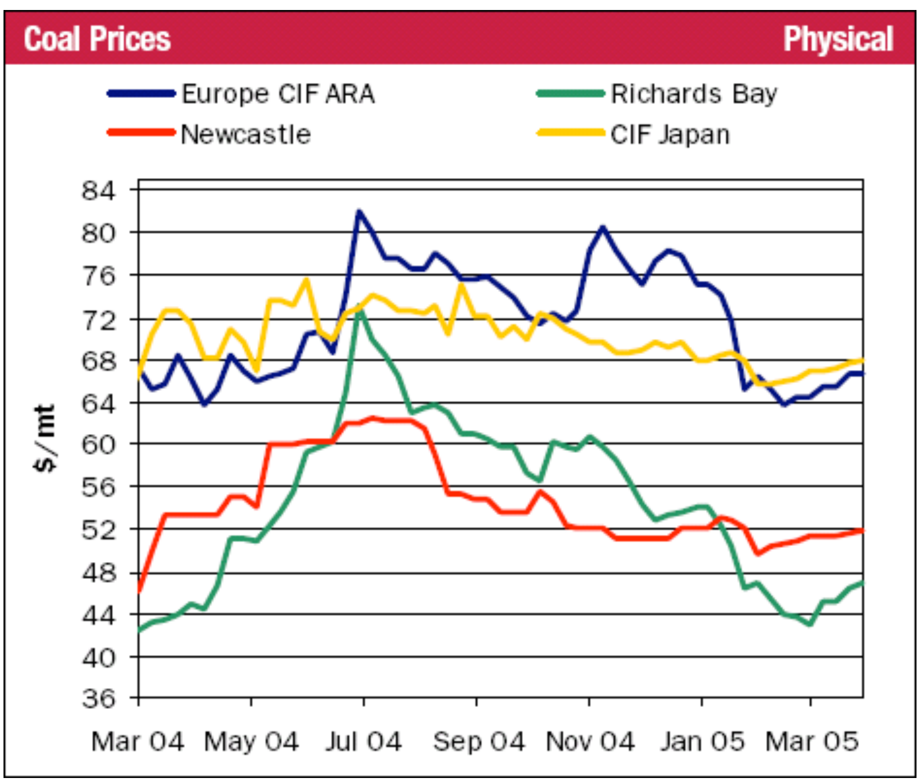
[9] http://www2.nrcan.gc.ca/es/erb/CMFiles/2005_Review_and_Outlook_English206PFM-02022007-2605.pdf
[10] http://www.ksg.harvard.edu/m-rcbg/repsol_ypf-ksg_fellows/Papers/Rosellon/IMPLICATIONS%20OF%20THE%20ELASTICITY%20OF%20NATURAL%20GAS%20.pdf



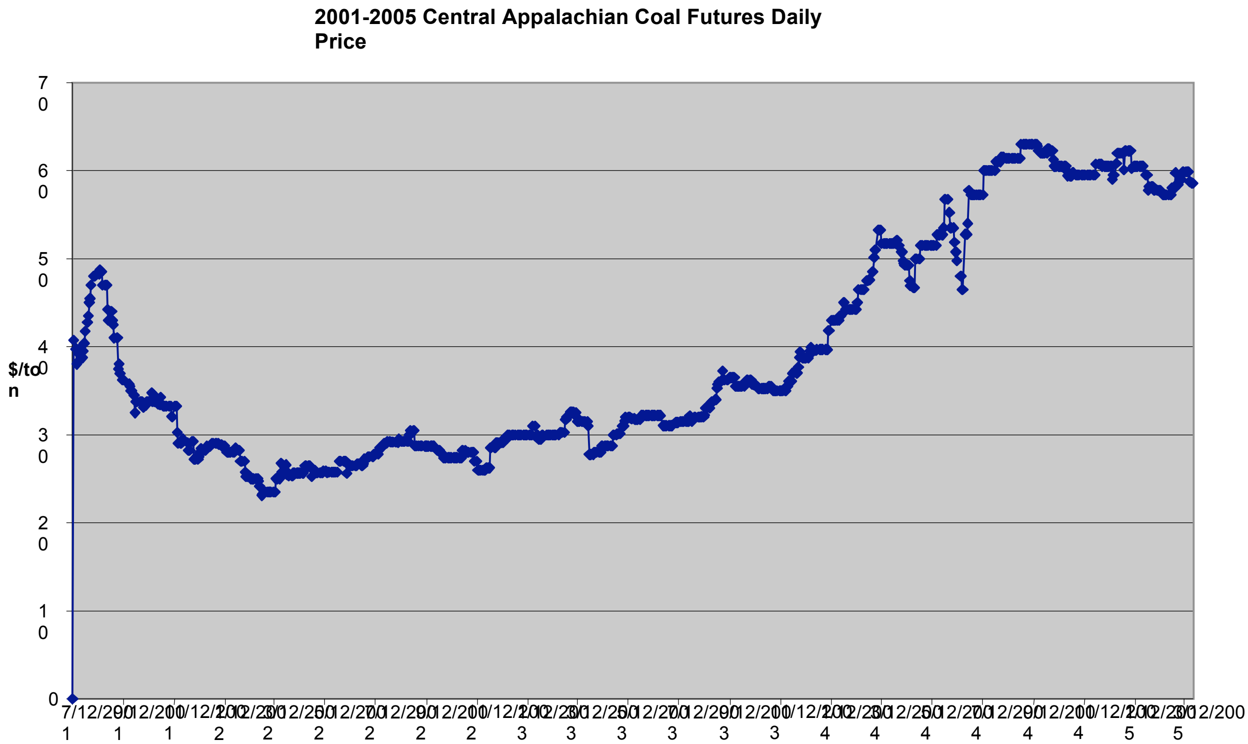
The graph below from Platts demonstrates worldwide coal price volatility, which was due to China's growing appetite for coal, weather events that limited transportation of coal, and declining production in the U.S. [11]



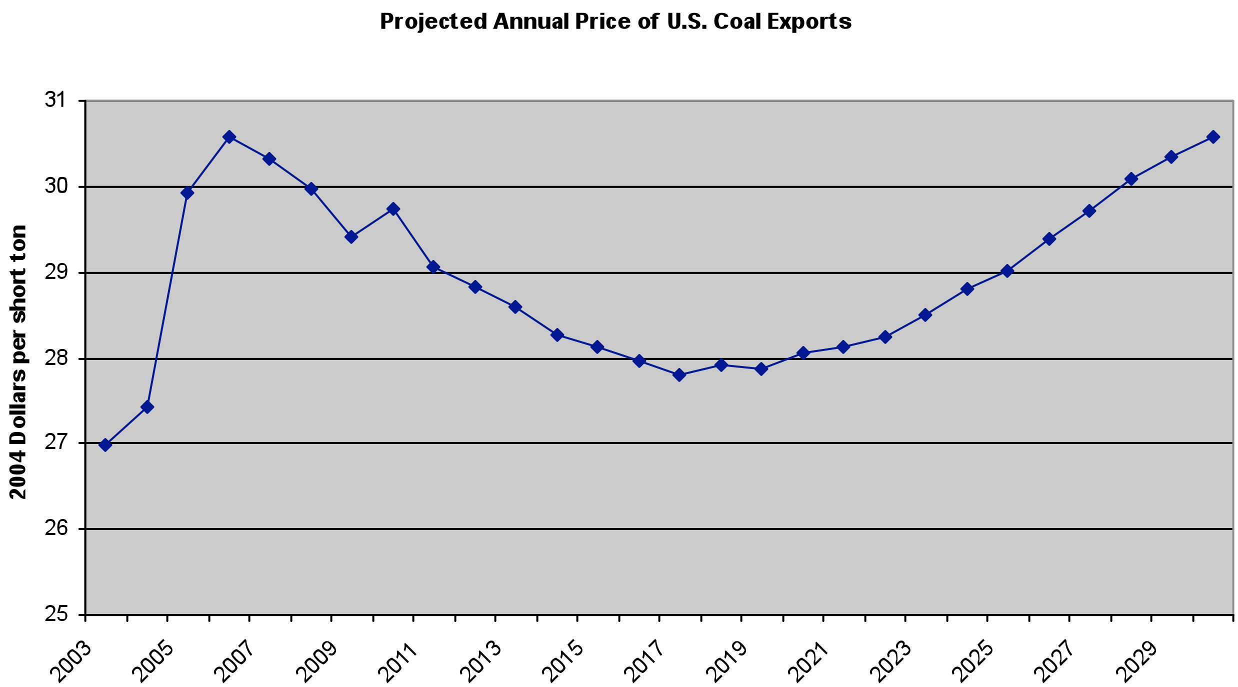
[11] http://www.platts.com/Coal/Resources/News%20Features/coal_prices_2005/chart1.html

In addition to price volatility, coal also carries considerable regulatory risk. In May 2006, Synapse Energy Economics conducted a review of the projections of 10 modeled analyses of costs of federal CO2 emissions limits and found that while it is difficult to pinpoint exactly what the future carbon-regulatory costs on coal will be, those future costs will certainly exist.[12]

Finally, we have the two forecasted prices of coal, both displaying considerable upward movement. The first graph displays actual coal futures prices over time, based on actual settlement prices. The second is a graph of projected coal export prices.



[12] http://www.synapse-energy.com/Downloads/SynapsePaper.2006-06.Climate-Change-and-Power.pdf

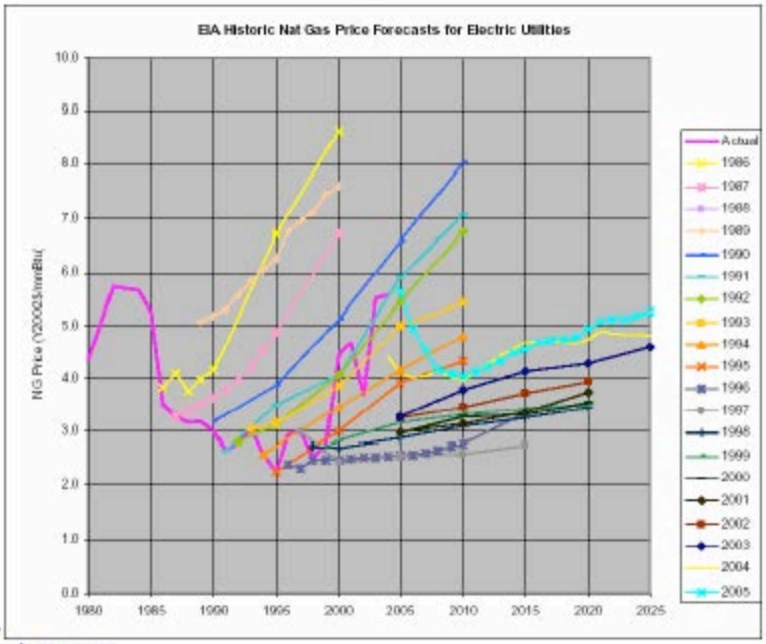


Oil prices have not only seen wide price swings recently, but in decades past as well. However, oil prices are not particularly instructive for this analysis since oil is not a major fuel source for electricity generation in the United States and Canada. Most of the existing generating capacity in Mexico is oil-fueled, but many of these power plants will be converted to utilize natural gas.[13]

History has shown that there is little relation between forecasts and actual prices. Forecasts cannot take unforeseen events – such as war, change in government, hurricanes or the effects of low precipitation on hydropower – into account. One report by the California Energy Commission stated, "The best assumption about all forecasts for commodities as volatile as natural gas is that they will be wrong."[14] Synapse Energy Consulting proved this theory true and put it in graphical form with its collection of gas price projections since 1975.[15]

[13] http://www.cslforum.org/mexico.htm
[14] http://www.energy.ca.gov/2006publications/CEC-100-2006-001/CEC-100-2006-001-CMF.PDF This document also has nice graphs of natural gas price forecasts.
[15] http://www.synapse-energy.com/Downloads/SynapsePresentation.2006-01.Forecasting-and-Using-Carbon-Prices-in-a-World-of-Uncertainty.pdf

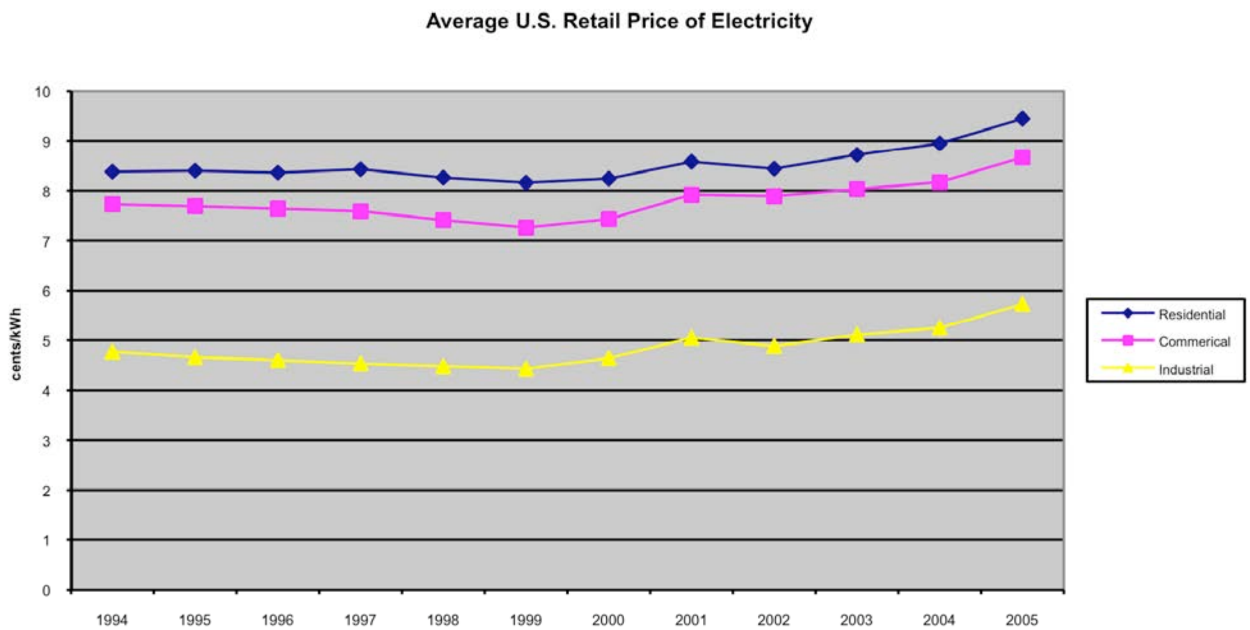
Gas Price Projections 1986-2005



Synapse Energy Economics

This unpredictability bolsters arguments in favor of renewable energy. Not only is there demonstrated volatility in fossil fuel markets, it is also coupled with a poor ability to forecast future prices.

The final piece of the data puzzle to consider is the price of electricity. As with the previous charts, the less granular the data, the less volatility is exposed. As an example, we present below the average historical national price, California's historical average price, then the historical average price by utility in California. Moving from graph to graph you will see increasing volatility, though these graphs cover overlapping time periods. Getting a finer level of granularity is difficult since the contracts signed by electric utilities are typically not available to the public.


Average U.S. Retail Price of Electricity
cents/kWh
10
9
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7
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5
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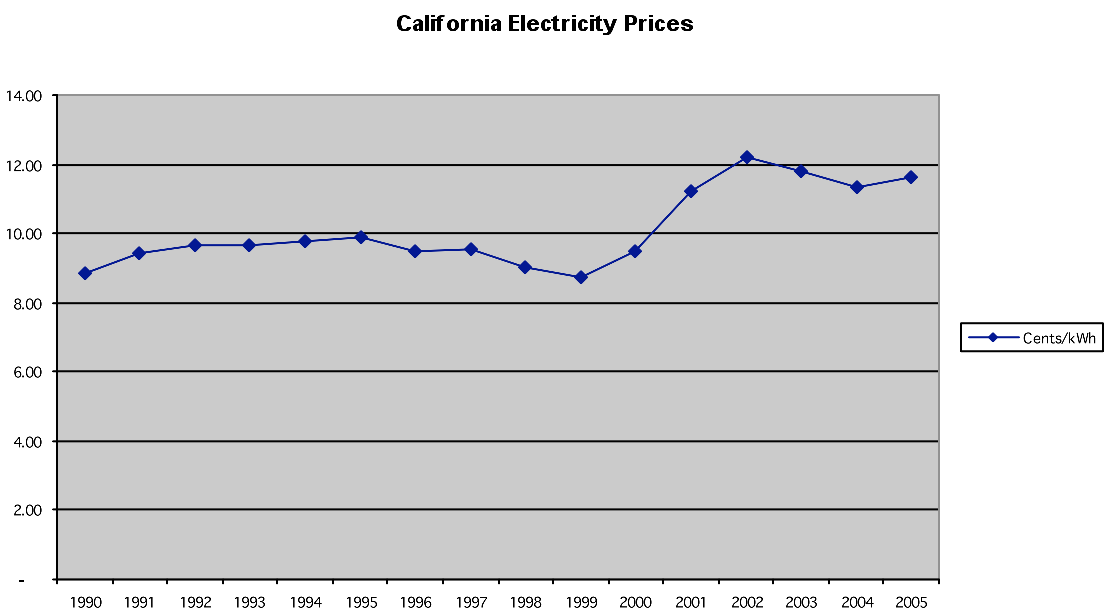
Residential
Commerical
Industrial


California Electricity Prices
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8.00
6.00
4.00
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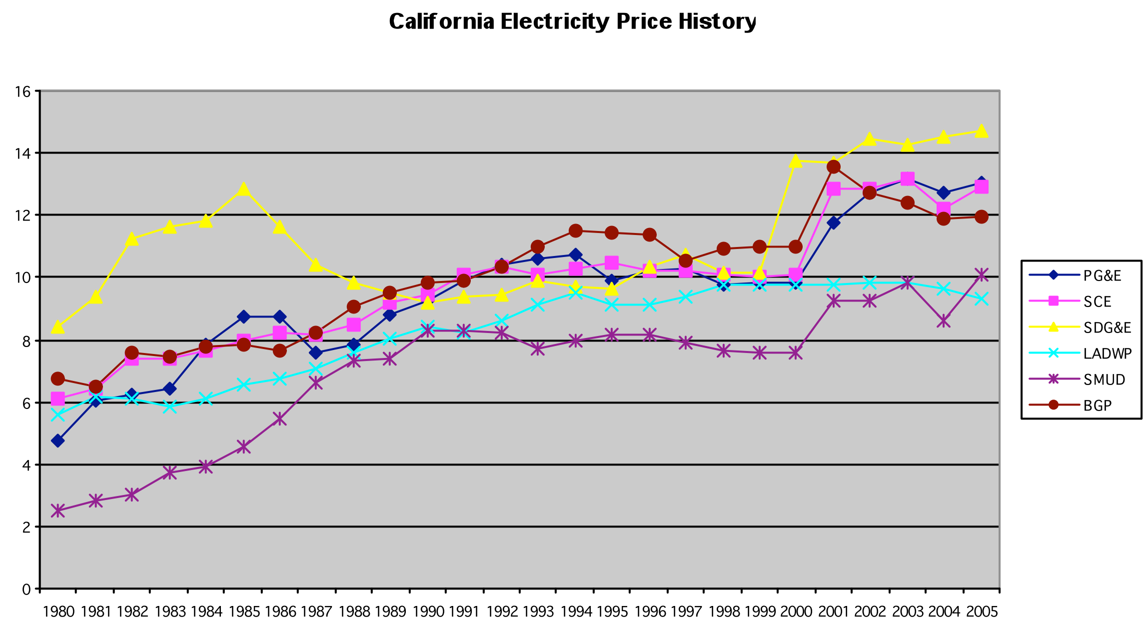
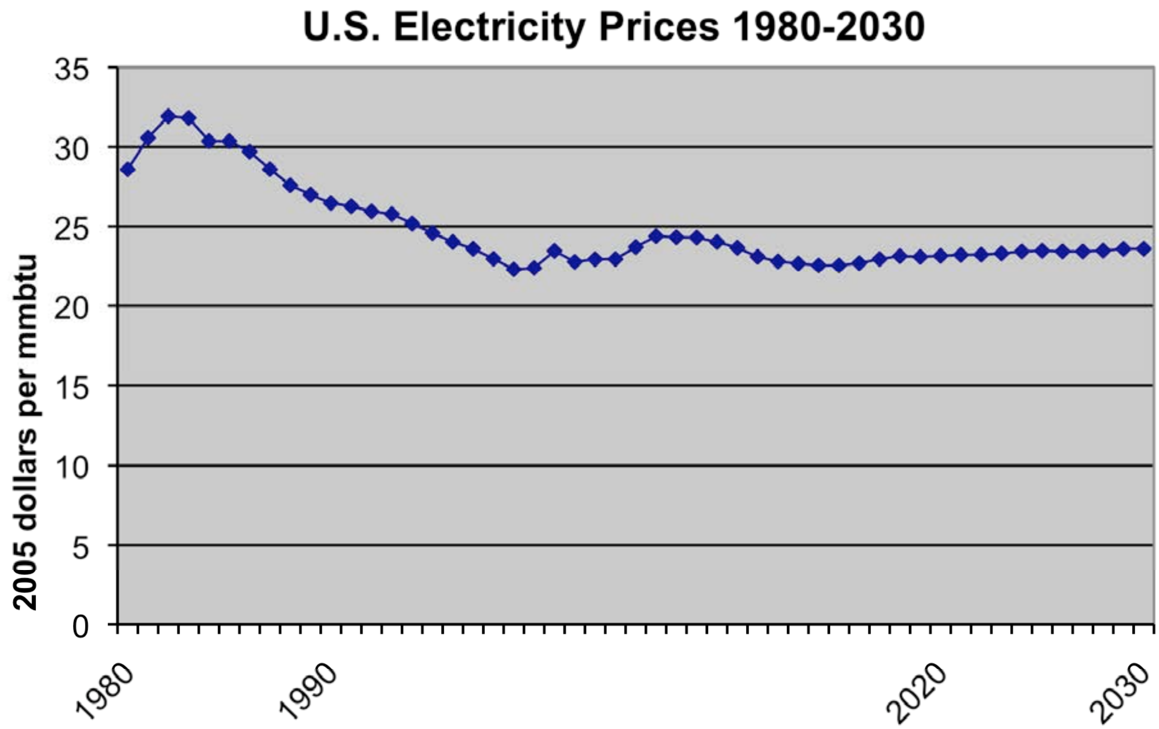


It was well publicized that California wholesale electricity prices went from $35 MWh to $375 MWh during 2000.

Given the volatility depicted by the graphs of electricity prices presented above and the inaccuracy of forecasting prices, we wonder how much faith should be put in the EIA's extremely stable electricity price forecast. Future natural gas prices are very difficult to predict for any nation. In theory, prices for non-renewable resources would rise in real terms over time. However, there are many mitigating factors. Technology improvements tend to reduce production costs, increase the efficiency of gas-using equipment, reduce gas demand, and reduce prices. Lower relative prices for other fuels may cause fuel switching away from natural gas, causing lower gas demand and prices. Finally, new supply areas and sources, such as northern Canada, liquefied natural gas, and coalbed methane, could increase supply thereby lowering prices."[16] Any of the mitigating factors may be superseded by events such as extreme weather, unexpected regulatory impacts, or acts of terror. Forecasts are made in a static environment, and it is impossible to predict some events that will have a major affect on price.

[16] http://www2.nrcan.gc.ca/es/erb/prb/english/View.asp?x=448#p12



Price volatility is a significant concern for electric utilities, their customers, and their shareholders. Market volatility not only affects rates, but also increases the other risks utilities face: transmission constraints, cost and availability of emissions allowances, blackout risk, political risk of cost recovery, and the ability of customers to pay. Price volatility in wholesale electricity markets can be handled in a variety of ways in terms of how electric utilities and their regulators manage financial risk. Typically, electricity consumers face stable prices determined by the administrative procedures of their state regulatory agency. Prices are set so as to compensate the vertically integrated regulated utilities for investments they made, with ratepayers, rather than shareholders, shouldering the risks. Price volatility and fluctuating contract prices are typically handled in fuel adjustment clauses, which address the cost of fuel risk. These allow utilities to recover increasing fuel expenses that occurred in a prior period. Typically, these rate cases are based on retroactive assessments of the utility's portfolio, so these are "hindsight" regulatory fixes, not prospective risk reduction strategies.

Some regions that have undergone deregulation have different means of handling volatility of electricity markets, but those are the exception. In many cases, regulators adopt policies that encourage greater price stability, such as encouraging long-term electricity contracts, price caps, reducing dependence on spot markets, and encouraging fuel supply diversity. As this paper demonstrates, renewable energy procurement is another tool in that toolbox.

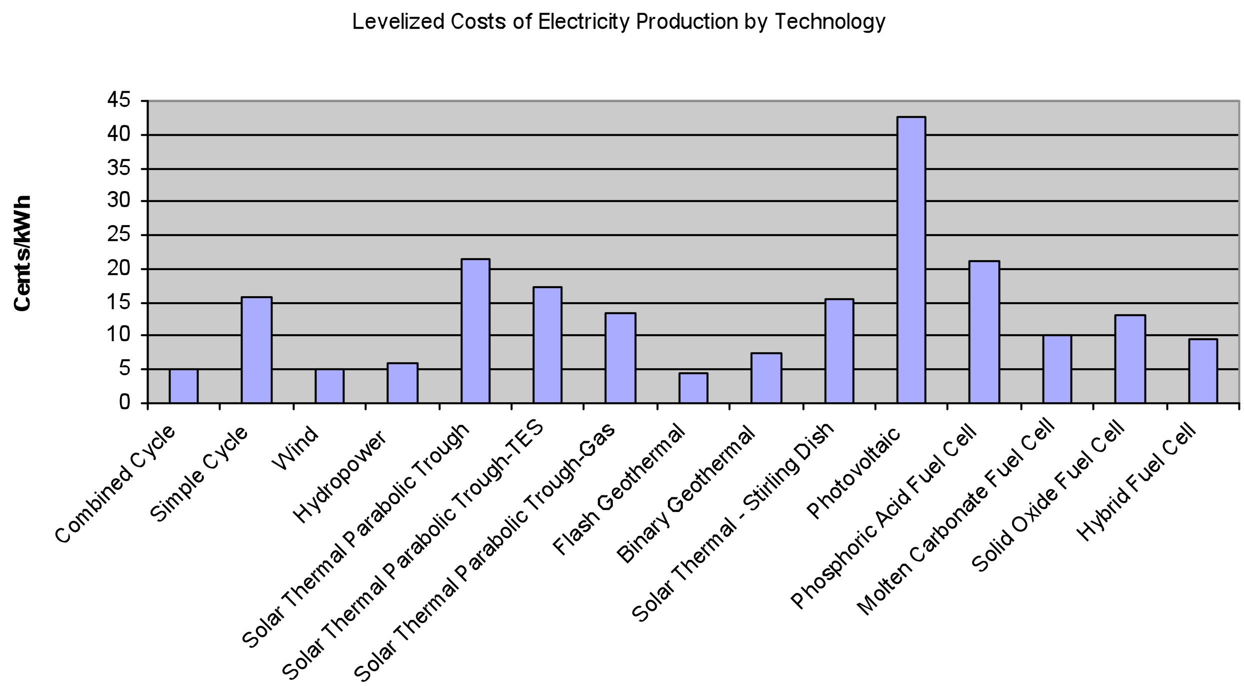
II. The Price Stability Benefits of Renewable Energy

The increased reliance on natural gas has been concurrent with increased renewable energy generation, which brings with it the price stability benefits of free-fuel generation from solar, wind, hydro, and geothermal sources. This section of the report examines available data demonstrating the price stability benefits of renewable energy. Renewable energy costs tend to be stable or decreasing over time, compared to rising or fluctuating costs for fossil fuel. The report presents below examples of levelized renewable energy generation costs by technology. While this does not lend itself to a direct comparison of fuel prices as presented above, it is important in illustrating the price stability of free-fuel renewables as compared to the volatile pricing of fossil fuels. It is also important to note that the delivery characteristics of the generation also affect price. For example, some technologies provide bulk power supply that competes against wholesale electricity prices (e.g. geothermal) while others (e.g. solar PV) usually compete against retail prices.

Energy consumers often ask the question "when will clean, renewable resources like solar and wind power be cost-competitive with non-renewables like natural gas and coal?" Increasingly, the answer to that question is "now." The past few years have seen the arrival of a watershed moment in electricity pricing, at least in some regions of the United States. Prices of renewable energy sources can, in some regions and for some technologies, now be competitive with non-renewable sources of electricity. While this cost-competitiveness is mostly limited to areas where natural gas and electricity prices are high, where renewable resources are abundant, and where renewable energy promotional policies are in place, it has been demonstrated that renewable energy can be effectively priced at or below the cost of what otherwise would be contracted.

The costs of electricity are based on a number of factors such as fuel prices, capital costs, operations and maintenance requirements, siting issues, and permitting. Electricity prices are further affected by supply/demand curves, subsidies, contract terms, and so on. As demonstrated earlier in the report, since there are so many factors that affect costs and prices in electricity markets, it is very difficult to simplify energy prices in an apples-to-apples price comparison of various electricity sources. This section of the report provides the best publicly available pricing points for renewable energy generating options, and discusses pricing trends of renewable energy as compared to fossil fuels.

Our research found a few resources that have calculated the levelized costs of electricity from various technologies and fuel sources. The California Energy Commission study gives a single estimated pricing point per technology, while the World Bank study gives a price range. The graph below was created from California Energy Commission data.



Source: California Energy Commission, 2003.

The World Bank report provides a wealth of data and condenses its analysis into the illustrative figures below.[17] The figures show in cents per kWh the average levelized costs for various renewable energy technologies. The first figure is for medium-sized systems and the second figure is for larger utility-scale systems. The bars represent the sensitivity range (low to high) with the point where the two colors meet representing the average.

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17 http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTENERGY/EXTRETOOLKIT/0,,contentMDK:20751106~menuPK:2069872~pagePK:64168445~piPK:64168309~theSitePK:1040428,00.html

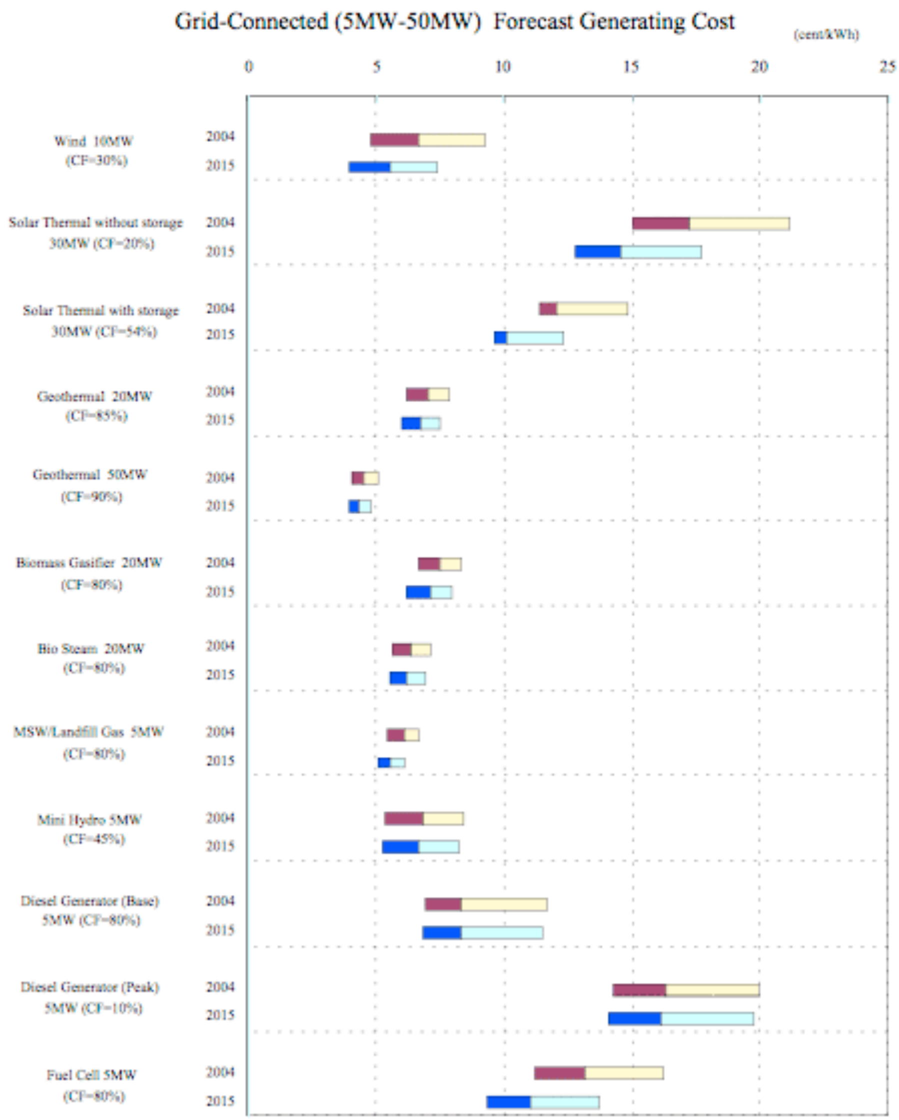


Figure 4: Electricity Costs: Small Grid-Connected Generation Technologies (2004 & 2015)

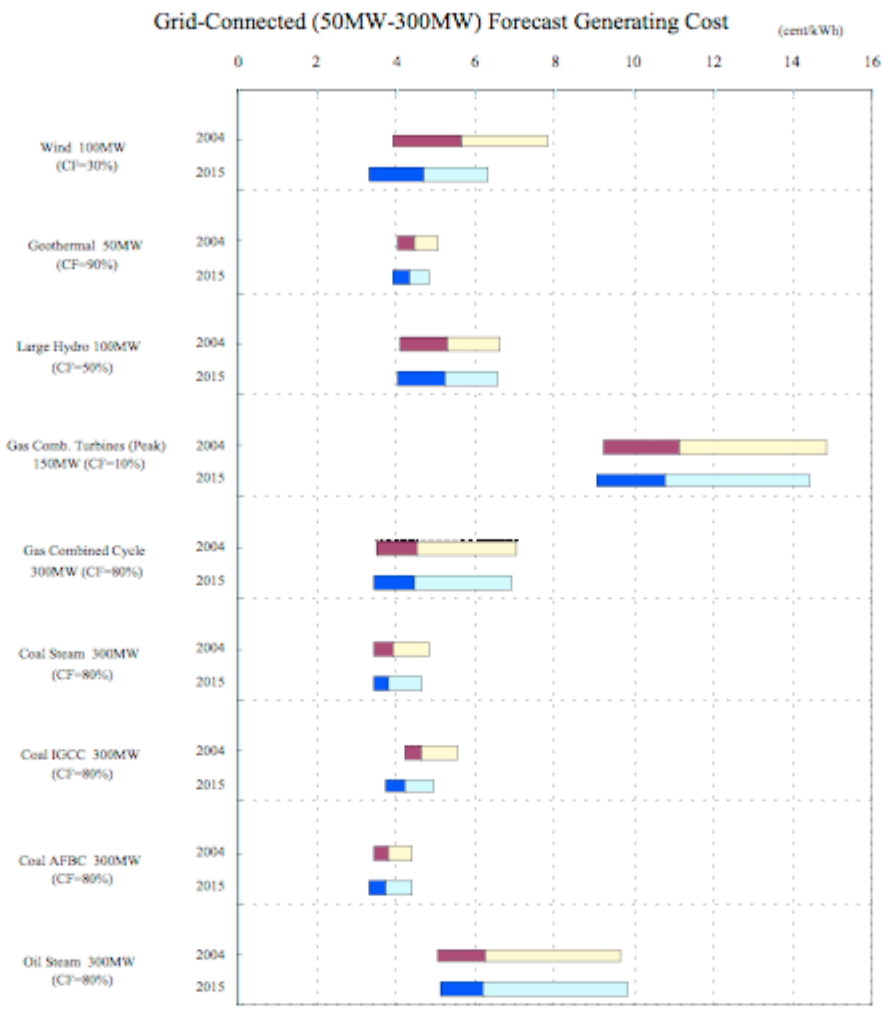


Figure 5: Electricity Costs: Large Grid-Connected Generation Technologies (2004 & 2015)

Both the World Bank and California Energy Commission studies agree that of the various types of emerging renewable energy, wind and geothermal are the most cost competitive with fossil fuels for generating electricity. For illustrative purposes, we now take a closer look at cost data for renewable energy applications in the United States. Though these numbers will be different for Mexico and various Canadian provinces, they should follow similar patterns even though the costs at different geographic locations may fall at different points on the cost curves.

Wind

According to the American Wind Energy Association, over the last 20 years, the cost of electricity from utility-scale wind systems has dropped by more than 80 percent.[18] The cost of wind has risen in recent years from roughly $1100 per kW installed to perhaps $1800 - $1900 per kW. Most people attribute this higher cost to rising concrete and steel prices, but a recent report by Ryan Wiser also suggests a weak dollar, a shortage of turbines, and a movement

[18] http://www.awea.org/faq/wwt_costs.html

toward increased manufacturer profitability.[19] In the early 1980s, when the first utility-scale turbines were installed, wind-generated electricity cost as much as 30 cents per kilowatt-hour. Now, state-of-the-art wind power plants can generate electricity for less than 5 cents/kWh with the Production Tax Credit in many parts of the U.S., a price that is competitive with new coal- or gas-fired power plants. The cost of wind energy varies widely depending upon the wind speed at a given project site, and a large wind farm is more economical than a small one.

Geothermal[20]

Real levelized costs for geothermal electricity generation are 4.5-7 cents per kilowatt-hour. Delivered costs depend on ownership arrangements, financing, transmission, the quality of the resource, and the size of the project. Geothermal plants are built of modular parts, with most projects including one or more 25-50 MW turbines. Geothermal plants are relatively capital-intensive, with low variable costs and no fuel costs. Usually, financing is structured so that the project pays back its capital costs in the first 15 years, delivering power at 5-10¢/kWh. Costs then fall by 50-70 percent, to cover only operations and maintenance for the remaining 15-30 years that the facility operates.

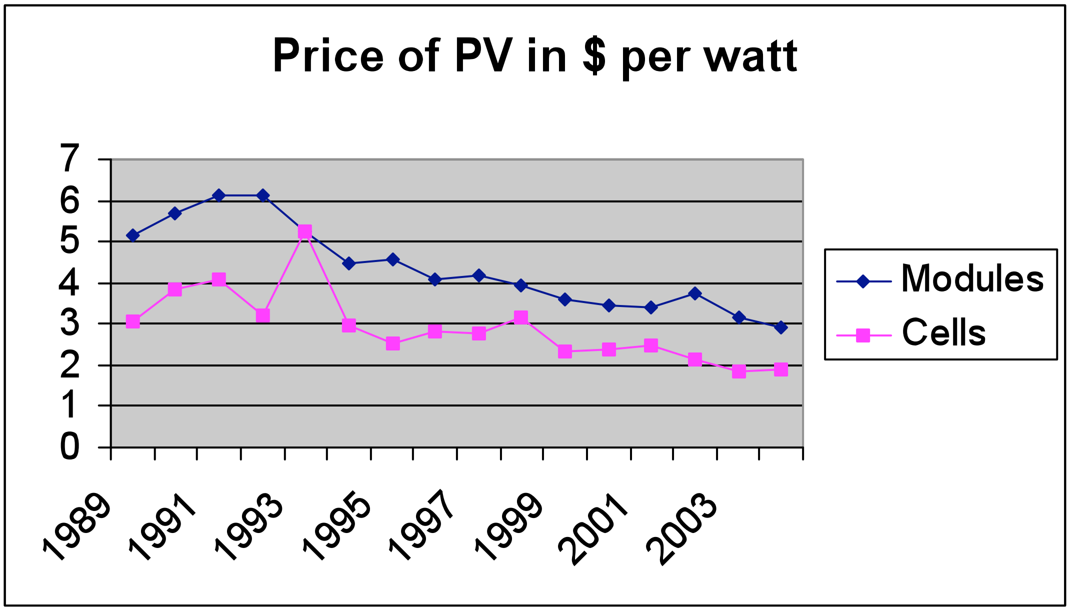
Solar

The website solarbuzz.com offers solar electricity benchmark price indices, comparing the levelized costs of solar to average retail electricity prices. As of January 2007, they estimate the levelized costs of PV as follows:

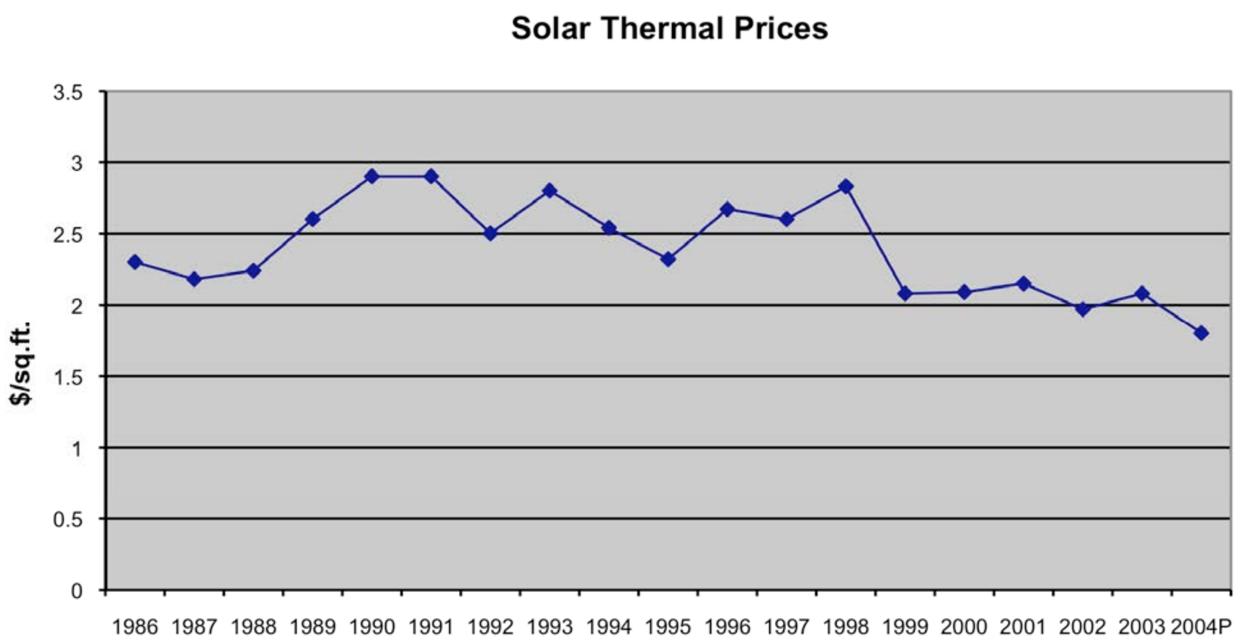
	Size of system	System Cost	Sunny Climate price	Cloudy Climate price
Residential	2 kW	$17,838	37.30 cents kWh	82.05 cents kWh
Commercial	50 kW	$342,782	27.48 cents kWh	60.47 cents kWh
Industrial	500 kW	$2,485,098	21.42 cents kWh	47.12 cents kWh

These prices do not take rebate programs into account, but show that solar PV prices need to drop considerably before becoming cost-competitive with fossil fueled generation. However, the graph below shows that PV prices have been on the decline over the past two decades.

[19] http://eetd.lbl.gov/ea/EMS/reports/ann-rpt-wind-06.pdf
[20] source: http://www.rnp.org/RenewTech/tech_geo.html



Similarly, solar thermal technology prices have been on the decline, as shown in the graph below.



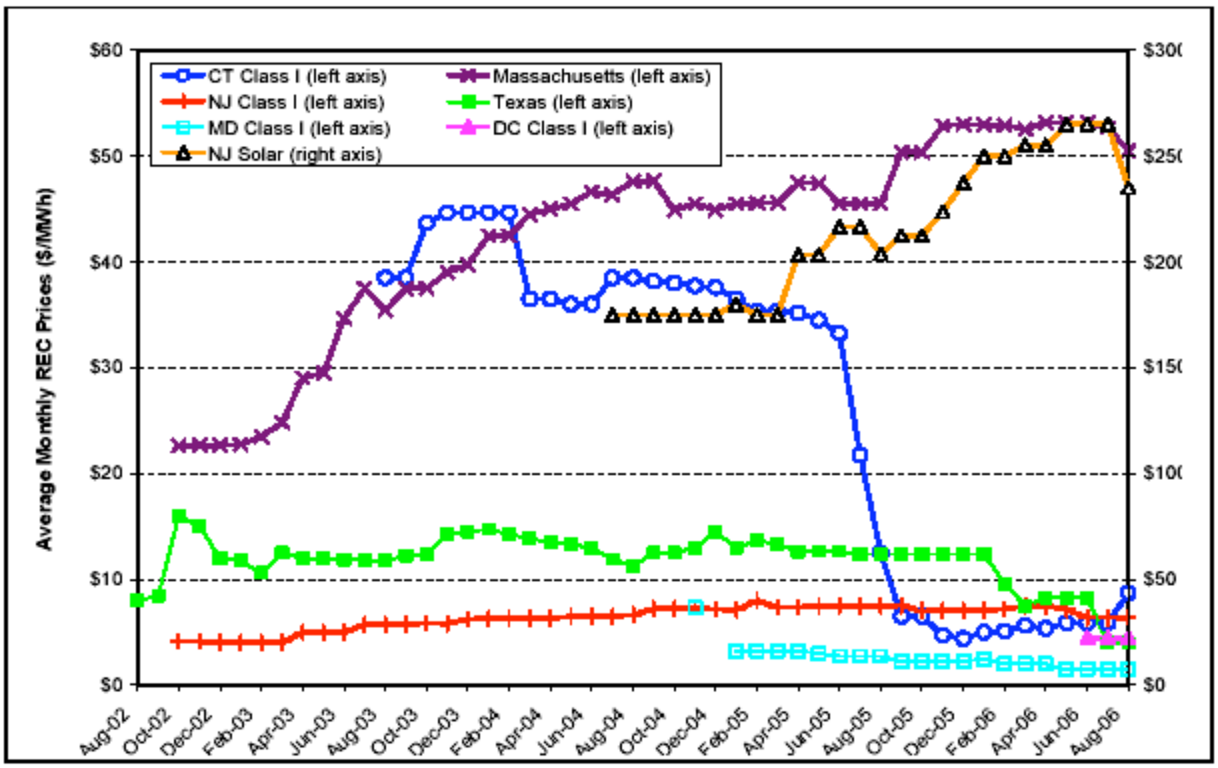
One important trait of solar related to energy costs is that solar tends to be a peak generation source. The power generation curve for solar PV fits well with the peak power demand curve.[21] Therefore, each MWh of solar PV generation provides great social benefit in reducing marginal demand when marginal prices are highest.

[21] For example, see http://www.state.mn.us/mn/externalDocs/Commerce/Relationship_between_solar_generation_and_electric_demand_111003025625_Solarpaper11-03.pdf

Renewable Energy Certificates

Some may look to prices for Renewable Energy Certificates (RECs) as an indicator of the price of renewable energy. Renewable Energy Certificates are often thought of as a tool to bridge the price gap between renewables and fossil fuels. However, REC prices are influenced by a number of factors such as the balance of supply and demand, penalties for non-compliance with renewable portfolio standards, and whether or not the RECs are sold into voluntary or compliance markets. The graph below summarizes the Monthly Market Updates for RECs provided by the brokerage firm Evolution Markets. The graph shows the tremendous volatility, regional price disparity, and illiquidity of REC markets.

Figure 10. Monthly Average Renewable Energy Certificate Prices



Source: Evolution Markets, Inc. Data Bank (http://www.evomarkets.com/index.html), compiled by Lawrence Berkeley National Laboratory. October 2006.

Source: http://www.energy.ca.gov/2006publications/CEC-100-2006-001/CEC-100-2006-001-CMF.PDF

The authors of this paper see a very important role for RECs in helping to finance new renewable energy facilities, and for documenting compliance with Renewable Portfolio Standards, but do not see REC prices as a meaningful indicator of renewable energy costs nor generally as a risk mitigation tool unless a special contracting scheme is used to capture that value (e.g. a Contract for Differences).

Comparison to Fossil Fuels

Perhaps the best proxy for the hedge value of renewable energy is the cost of securing natural gas or coal supplies over time at a fixed price. The report "Power Price Stability: What's it Worth" concluded that the combined cost of meeting gas deliverability requirements through the use of gas storage and of fixing future gas prices using options is $5.20 per megawatt hour as a lower bound (i.e. actual cost would likely be higher), and estimated that $5.50/MWh represents a proxy for the value of the physical hedge provided by renewables.

Some regions are so dependent on natural gas that natural gas prices become strongly correlated with electricity prices. This is certainly the case in Texas. The Association of Electric Companies of Texas reports that as the marginal fuel for electric generation in the Electric Reliability Council of Texas (ERCOT) is natural gas, wholesale power prices are 98 percent correlated with the price of natural gas.[22]

As presented earlier in the graphs of coal forward prices and price projections, coal prices are also on an upward trend, making renewable energy investments look increasingly more attractive to electricity providers and customers alike.

The point is often made that renewables, while price stable, are more expensive than conventional power. Therefore, renewable power may be less volatile, but consistently more expensive, than conventional power - resulting in a hedge that guarantees you always pay more. In practice, this gap does not always exist and is quite geographically and/or temporally specific. There are a number of case studies demonstrating how renewables are in some regions price-competitive with conventional power, and even Integrated Resource Plans that have identified renewables as least-cost in all-source bidding (see the case study " Public Service Company of Colorado 2003 Least-Cost Resource Plan," in this report). Moreover, as this report argues, there are other monetizable values of renewables that may bridge the cost gap between renewables and conventional sources in cases where renewables are "more expensive." Of course, there are cases where renewables are clearly more expensive even when other values are considered. This report is not suggesting that the hedge value of renewable energy will make renewables the best financial deal in all cases.

[22] http://www.aect.net/documents/2003/20030306_IP_WholesaleRising.pdf

III. How Can the Price Stability Benefits be Conveyed to Customers?

The first section of the report presented various data points that painted a landscape of volatility and unpredictability in electricity markets, primarily due to wildly fluctuating natural gas prices. The second section offered the price stability benefits of free-fuel renewable energy resources. This section ties those two parts together by presenting conceptual ideas of how renewable energy can provide a hedge. A number of practices are presented, and those are further examined in case studies. In general, there are two key ways that renewable energy provides a financial hedge:

1. Since renewable energy resources (with the exception of biomass) do not require purchased fuel, the operating costs over time are highly predictable, as opposed to fossil fuel markets.
2. Renewable energy reduces the demand for non-renewable resources, potentially easing prices of fossil fuels.

The first point suggests an approach through which an energy supplier or even individual energy consumer can privately benefit from the price stability of renewable energy. The second point depicts the public benefits that renewable energy provides for all energy consumers. This section of the report will cover both the individual and the socialized price stability benefits that renewable energy provides.

Utility and Energy Marketing Models

Renewable energy can provide hedging solutions for utilities or other load serving entities at the utility-scale, and can also provide price stability benefits for retail customers who receive price-stable purchasing terms or install renewables on their side of the meter. Several means of tapping into the price stability benefits of renewables, both for electricity providers and their customers, are explored below.

Long-term Fixed Contracts with Non-residential Customers

Long-term contracts are an increasingly attractive option for both providers and consumers. Electric utilities and retail electricity providers can tap into their customers' interest in price stability and environmental protection by offering a renewable energy option at a fixed, long-term (5–10 year) price. The report by World Resources Institute's Green Power Market Development Group entitled "Developing Next Generation Green Power Products for Corporate Markets in North America" explains in detail how this can be accomplished, and provides a case study.[23] Our report also contains a case study of Austin Energy, the most successful proponent of this approach.

Renewable energy projects often require a longer-term (>10 year) power purchase contract to ensure reasonable financing terms because of their up-front capital intensity. Renewable-generated electricity can therefore offer a longer-term hedge than many of the conventional hedging strategies, which often focus on short-term markets. Even where long-term

[23] http://pdf.wri.org/gpmdg_corporate_6.pdf

conventional hedges are available, these markets are often thinly traded so transaction costs would be expected to increase, creating a higher benchmark against which a renewable power hedge would be measured.

In contrast to gas-fired generation, long-term contracts for renewable energy are typically offered on a fixed-price basis. To obtain a similar hedge with gas-fired generation (using gas forwards) over the last four years, one would have to pay a substantial premium relative to the most commonly used gas price forecasts in the USA. (Reference 1)

Some customers may choose to hedge only a portion of their electricity use. For example, a company may have the alternative of selecting a supply option of 20 percent renewables and 80 percent system power. This arrangement may be palatable when renewables carry a small price premium over the current cost of system power. The company may see a 20 percent hedge as an attractive offering, since they may be concerned that system power costs will rise, and will be willing to pay a small premium for renewables to diversify their energy portfolio and limit their exposure to fossil fuel price increases. On the other hand, some companies may opt for a 100 percent renewable option even when the price per MWh is higher than for system power; they may wish to make environmental claims and/or they may see the increased price stability and certainty of their operating costs as being worth the price premium.

This product type also tends to work well for the utility/marketer and/or generator, because in the signing of a long-term fixed price contract with the customer, they receive financial stability they can take to the bank.

There have been some barriers in the United States to long-term contracting for renewable energy. Some utilities may be resistant to sign because of their experience of signing PURPA QF[24] contracts with escalator clauses, only to experience a downturn in energy prices, leaving utilities with stranded costs. Also, as demonstrated in the era leading to California's energy crisis, it is much more difficult to get long-term contracts in restructured or restructuring markets because loads may shift to a competitor, or because regulators or legislators with anti-competitive concerns may discourage or prohibit utilities from entering into long-term contracts.

Adjustments to Monthly Bills

Some electric utilities that offer their customers a green pricing option have begun extending the price-stability benefits of renewable energy to their customers by exempting those customers from fuel adjustment clauses. When utilities apply fossil fuel rate increases, they may opt to exempt their green pricing customers, thereby passing along the price stability benefits of renewables to their renewable energy customers. This exemption may mean that the advertised price of renewables is higher than the effective price, as the customer's bill will include a zeroed-out line for fossil fuel adjustments as well as a price premium for renewables. In other words, when fuel prices increase, the effective green power premium falls. By bundling the hedge value of renewable energy with a green power product offering, the hedge may provide additional

[24] A Qualifying Facility (QF) is a generating facility, typically a small renewable energy facility, which meets the requirements for QF status under the Public Utility Regulatory Policies Act of 1978.

value to a green power purchaser. With renewable energy products that offer benefits beyond the traditional environmental sales pitch, customer demand for green power may increase. A number of electric utilities in the United States offer this type of green pricing product, including Alliant Energy, Clallam County PUD, Edmond Electric, Eugene Water and Electric Board, Green Mountain Power, Holy Cross Energy, Madison Gas & Electric, OG&E Electric Services, We Energies, and Xcel Energy. These are some of the most successful green pricing programs in the United States, according to the National Renewable Energy Laboratory's Green Power Network.[25]

The utility green pricing examples cited above are all in regulated utility markets. The approach described above may be impossible in restructured markets where the utility provides transmission and distribution only and is not responsible for supply. In those cases, the competitive electricity marketer may choose to offer a price-stable renewable energy option.

Contracts for Differences (CFD)

Contracts for differences, like long-term contracts, can provide hedging benefits both to the buyer and the seller. It may be possible to finance projects in the absence of a utility Prospective Purchaser Agreement (PPA) if large, creditworthy end-users, such as universities or government agencies, make long-term commitments (i.e. 10 years or more) to purchase stand-alone RECs or RECs bundled with energy. For example, a REC contract for differences would provide price stability to the buyer and revenue security to the seller. While it provides budgeting certainty for the end-user, most are uneasy about making long-term budget commitments for energy.

A green CFD is a financial contract that allows a customer to support renewable energy development, acquire RECs, and hedge against fluctuating electricity rates—but does not involve the customer receiving physical power. [26] Rather, the contract sets up an exchange of payments between a power consumer and a renewable generator that hinges upon an agreed price for power.

The contract for differences is a purely financial product. Under this arrangement, the customer continues to receive its electricity supply from the default service provider or from a traditional energy services company (ESCO). The price of the supply would not be fixed. A separate, financial CFD is signed with a renewable generator or intermediary. Under this contract, a fixed hedge price is established (e.g. $0.05/kWh), also referred to as the strike price. The customer would then pay the renewable supplier a floating premium for each kWh generated, which varies depending on the difference between the fixed hedge price and a variable underlying index at the time of production. If the variable index price is lower than the fixed hedge price, then the customer will pay that difference to the renewable supplier. However, if the variable index price exceeds the fixed hedge price, the renewable supplier would pay the customer. This provides a benefit to both parties—the generator gets revenue certainty, while the buyer gets a hedge against volatile or rising electricity prices, as well as the RECs.

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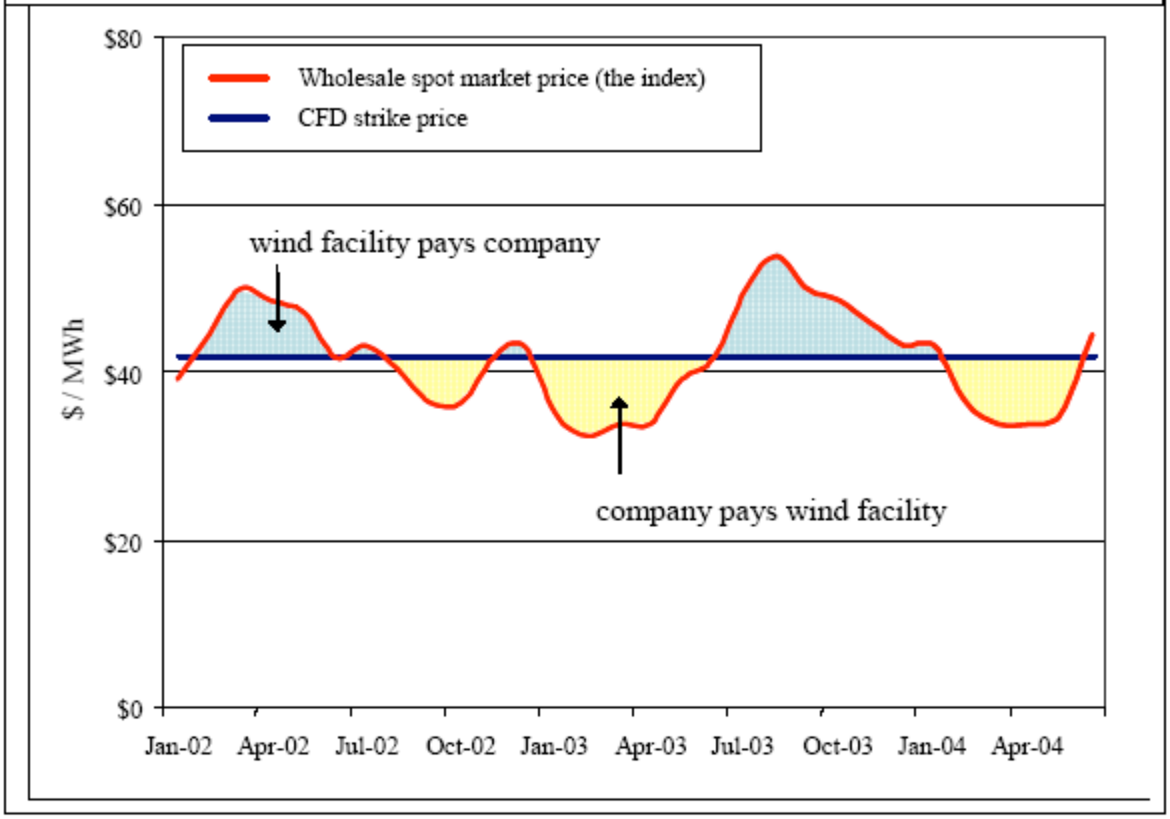
[25] http://www.eere.energy.gov/greenpower/markets/pricing.shtml?page=3

[26] See case study on the City of Calgary, Alberta, Canada later in this report.

Figure 1: How a Green CFD Works
w a green contract for differences w



Source: Robert C. Grace et. al.
http://www.mtpc.org/renewableenergy/public_policy/DG/resources/2005-05-16-AWEA-Grace-WIndHedge.pdf

Such a CFD is a perfect hedge for a renewable generator if the generator sells the energy into the same spot market to which the CFD is indexed. If renewable energy production is low (high) at times when the index price exceeds (falls below) the fixed hedge price, however, this CFD will provide a poor hedge for the customer. On the other hand, the customer will profit under this CFD if the reverse is true. While a perfect full hedge for a customer is not possible, renewables may provide an acceptable and attractive hedge if the prices faced by the generator and the customer are positively correlated, and production and consumptions patterns are reasonably well aligned.

Contracts for Differences is not an easy financial model for the layperson to comprehend. It is a relatively new financial model for renewable energy applications and there are few retail examples yet. Therefore, it may be a market-savvy model with limited application.

Fuel Switching from Fossil to Renewable Fuels

Fuel switching involves utilizing renewable fuels instead of fossil fuels when fuel prices reach a tipping point. Renewable fuels are basically various types of biomass. This strategy can be used by utilities or by commercial/industrial customers with on-site generation. For example, a facility running diesel generators could fuel-switch to biodiesel when petroleum-diesel prices reach a certain price point. Conversely, a facility may opt to use biomass fuel when biofuel prices drop below a certain point – for example, following a storm when organic debris may be in ample supply.

Customer Side of the Meter Models

Adjustment to monthly bills and on-site options are primarily retail customer solutions.

On-site Solar Service Model

Solar power has suffered for the last few decades from being "the next big thing" without ever becoming widely adopted by consumers. While the cost of solar power has come down tremendously in the last three decades, solar still makes up only a small fraction of a percent of electricity consumed.[27] This is in large part due to solar's large up-front capital costs, which result in long payback periods for buyers.

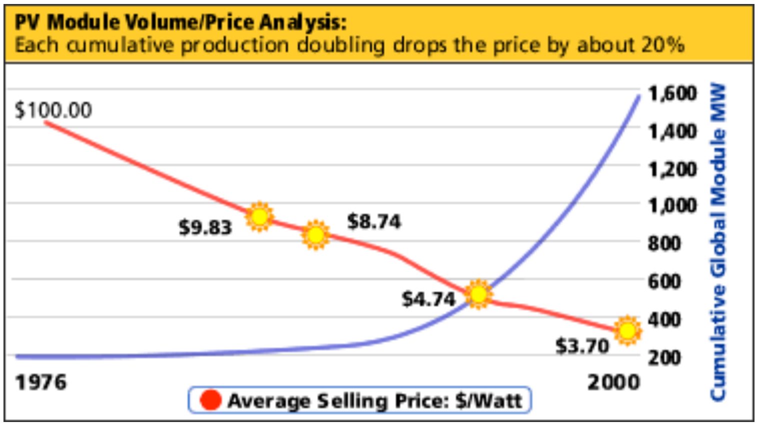
A new approach to financing solar is beginning to remove solar's front-loaded financial barriers, while allowing the customer to capture the price-stability benefits that solar provides. This model, pioneered by SunEdison (see case study on page 32) is known as "solar energy services." The traditional model of a solar installer is to sell and install the equipment and perhaps make arrangements for financing. With the solar services business model, the vendor owns, installs, operates and maintains the solar power plants at the customer's facility, while the customer benefits from predictable energy prices without paying high initial capital outlays. This also simplifies the process for the customer, since SunEdison provides a turnkey service.

It is worth noting that in some cases solar service providers offer to peg solar electricity rates at a level below retail. While that approach does signify savings for the customer it does not address price volatility. Solar service providers want to offer customers a variety of pricing points to meet individual customer needs, and some customers may prioritize comparative savings over price stability.

On-site Generation

Generating renewable energy onsite, particularly solar, is an increasingly popular way for customers to take control of their energy costs. With the costs of solar photovoltaic equipment decreasing over time, coupled with rising electricity costs and low interest rates, on-site generation is becoming more economical every year.

[27] Solar power generated 534,000 MWhs in the U.S. in 2003 of 3,883,185,000 total generation, or 0. 01%.



Source: Solar Energy Industries Association, http://www.seia.org/images/learnmore/smalldoubling.gif

Wind power, hydropower, geothermal and biomass can also be suitable renewables for on-site production but tend to be more site-specific. Since renewable energy sources (excluding biomass) are fuel free, their costs are predictable. Every MWh generated on-site is one fewer purchased from an electric supplier, whose rates may be based on volatile fossil fuels. Companies whose operation creates suitable biofuels as a by-product, such as agriculture, water treatment, and the pulp and paper sector, have ample opportunities to turn the waste stream into an on-site fuel source. In some cases, this may reduce disposal fees while creating a stable source of clean energy.

The distributed nature of onsite generation also provides public benefits. Distributed generation can decrease transmission requirements, thereby increasing the reliability of the grid.

Time-of-use Metering Combined with Solar Net Metering

Many electric utilities now offer time-of-use rates as a way to encourage customers to reduce their electricity consumption during peak hours. With time of use rates, a customer's electric rates will vary during the day (typically as "peak" and "offpeak", though there may be more gradations). Electricity used during peak hours will be more expensive than the standard rate, while energy used off-peak will be less than the standard rate.

Net metering, for consumers with generators on their side of the meter, allows electricity to flow in either direction through a bi-directional meter. When the customer's generation exceeds his/her use, electricity from the customer's facility flows into the utility's distribution grid.

Operating a solar PV system with the combination of net-metering and time-of-use rates can be an effective way to use renewable energy to reduce and stabilize energy cost because solar PV typically generates at maximum capacity during peak pricing hours. Therefore, a customer may be able to use PV to run the meter backwards during peak hours, generating credits with its electric utility. When the sun is not shining, the customer is buying power from the utility and the meter spins forward. The correlation between hours of sun and peak electricity prices is key to achieving price stability with this model.

Policy-Driven Models

Renewable Portfolio Standards

Renewable Portfolio Standard (RPS) policies are aimed at increasing the contribution of renewable energy in the electricity supply mix. Renewable Portfolio Standards typically require that a certain percentage of a utility's overall or new generating capacity or energy sales must be derived from renewable resources. The RPS is generally intended to create a stable and predictable market for renewable electricity that maximizes the benefits of renewable generation while minimizing costs.

About half of U.S. states have an RPS program, while three Canadian provinces have a renewable energy mandate and seven provinces and three territories have 'RPS-like' energy targets.[28] When established, advocates for the law often include price stability as a key benefit. Preliminary evaluations of RPS laws indicate that RPS programs have some price stabilizing benefits. A recent report reviewed 28 distinct state- or utility- level RPS cost impact analyses completed since 1998.[29] The survey found that renewable energy provides significant price stability benefits by being a fuel-free energy source as well as reducing demand for fossil fuels, which effectively lowers prices for fuels such as natural gas and coal. Specifically, the report found that, in the year that each modeled RPS policy reaches its peak percentage target, base-case retail electricity rate increases of no greater than one percent were projected for 70 percent of the 28 RPS cost studies. In six of those studies, electricity consumers were expected to experience cost savings as a result of the RPS policies being modeled.

A recent study by Center for Resource Solutions of California found that that gas prices would be reduced by an average of $0.02-0.06/MMBtu during the 2011-2020 timeframe (see the case study at the end of this report for more detail), and other studies concur.[30] A study of Virginia assumes that each MWh of renewable generation will result in three dollars of consumer savings, and a study of Maryland models two scenarios in which natural gas prices are assumed to fall by 2 percent and 4 percent relative to the reference case forecast – all as a result of implementing a renewable portfolio standard. In fact, experts find that consumer natural gas bill savings are sometimes projected to be large enough to eclipse the electricity bill impacts of some RPS policies.[31]

Whether managing investments or energy supply, a diverse portfolio is desirable because diversity reduces risk. Adding renewable resources to the electricity generation portfolio reduces the risks posed by over-reliance on a single source of electricity and reduces costs when the costs of producing electricity from nonrenewable sources are high.

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[28] "Fostering Green Power Markets: Opportunities for Growing the North American Green Power Market." Commission for Environmental Cooperation, 2006.
[29] http://eetd.lbl.gov/EA/EMP/reports/61580.pdf
[30] See Bolinger, Chen and Wiser. 2007.
[31] See Bolinger, Chen and Wiser. 2007.

Integrated Resource Planning

Integrated resource planning (IRP) is a framework for utilities to identify the best (and in many cases the cleanest) portfolio of electricity supplies at the lowest price over the timeframe of the plan. IRP offers a way to compare a wide range of resource alternatives in a balanced manner. Resource plans began as a way to identify the least cost sources of energy supply. However, over time, some states have required consideration of social costs (i.e. environmental externalities) and demand side measures to reduce load. Recently IRP has been used to conduct more sophisticated risk assessment.

While resource plans differ from one utility to the next, most are structured according to the following common basic framework:

1. Development of peak demand and load forecasts;
2. Assessment of how these forecasts compare to existing and committed generation sources;
3. Identification and characterization of various resource options to fill a forecasted resource need;
4. Analysis of different resource portfolios under base case and alternative future scenarios; and
5. Selection of a preferred portfolio and creation of a near term action plan.[32]

In markets with retail electricity competition, resource planning is often referred to as portfolio management.

Renewable energy resources were once barely considered in utility resource plans. However, a number of recent western resource plans, including Avista, Idaho Power, NorthWestern Energy, PacifiCorp, Portland General Electric, Public Service Company of Colorado, San Diego Gas and Electric, and Puget Sound Energy include sizable renewable additions that are independent of RPS obligations.[33] In aggregate, 3,380 MW of wind and 270 MW of other renewables not required by an RPS are planned by western utilities. This change reflects the fact that renewable resources and particularly wind power are increasingly found to be a useful contributor to low-cost, low-risk portfolios. It is also worth noting that many utilities in the United States are either subject to, or expect to be subject to, a state and/or federal Renewable Portfolio Standard that would require the utility to provide at least a specified minimum amount of renewable energy to all customers, so there may be overlapping motivations for renewable energy development.

Utilities' inclusion of renewable energy in resource plans is primarily motivated by:

1. Improved economies of wind power;
2. Growing acceptance of wind and other renewables by electric utilities; and
3. Increasing recognition of inherent risks in fossil-based generation portfolios (for example, natural gas price risk and environmental compliance risk).

[32] http://eetd.lbl.gov/ea/EMS/reports/58450-summary.pdf
[33] See case study on Public Service of Colorado's IRP later in this report.

Increasing the inclusion of renewable energy in integrated resource planning offers the opportunity to reduce a utility's exposure to certain electricity sector risks. As mentioned above, renewable energy can act as a hedge against natural gas price risk and risk of future environmental regulations, most notably carbon regulation. Those IRPs that have evaluated natural gas and carbon risks are now regularly finding that wind power and other renewable energy options are a beneficial contributor to a low-cost / low-risk portfolio. However, the efficacy of including renewable energy in resource planning depends to a large extent on cost and performance assumptions for renewable energy technologies, the treatment of risks and the range of candidate portfolios considered.

If renewable resources are not accurately or adequately represented in utility portfolios, or if a broad range of options is not considered, the outcome could be suboptimal. A review of western resource plans found that most utilities constructed candidate resource portfolios by hand and featured resources that passed initial cost or performance screening tests. This process may allow human bias to influence the outcome. The review also found that, in many cases, a full range of renewable energy technologies was not evaluated; rather, utilities limited their analysis to wind and, in some cases, geothermal energy. In addition, the utilities limit the amount of renewable energy additions in order to limit integration costs related to wind energy. The review found that for utilities subject to an RPS, none of the plans reveal any analysis that looks at whether renewable energy additions above and beyond the RPS would have financial merit. Each of the utilities subject to an RPS essentially consider the RPS to be the sum total of their planned renewable energy commitments, effectively capping planned renewable energy additions at the RPS. This puts an artificial ceiling on the potential benefits of renewable energy.

Also important to consider are cost and performance assumptions made for various renewable technologies including the total modeled cost of the renewable resource, transmission expansion costs, integration costs and the impact of the production tax credit (PTC) on wind costs. Many utilities calculate the PTC impact in a pre-tax rather than after-tax manner, thereby significantly understating the true value of the PTC to most wind projects.

The treatment of risks may also affect the degree to which resource plans rely on renewable energy versus more conventional sources of electricity production. Resource plans generally evaluate the following risks:

1. Natural gas price uncertainty
2. Wholesale electricity price uncertainty
3. Variations in retail load and departing load (the latter being a particularly acute risk for utilities in an RPS state where direct access is possible)
4. Hydropower output variability (i.e. drought)
5. Environmental regulatory risks

Short-term variability in gas prices can be mitigated with gas storage, fuel switching, and natural gas hedge contracts (forwards, futures, swaps, and options). Hedging long-term natural gas price risks is much more difficult. The most obvious approach to mitigating long-term natural gas price risk is through ownership or purchase of electricity sources whose price is not tied to that of natural gas (i.e. coal, nuclear, or renewable energy). As mentioned above, these sources provide two hedge benefits:

1. By replacing variable-price gas-fired generation with fixed-price electricity production, these sources directly reduce exposure to gas-price risk.
2. By reducing demand for natural gas, these sources may relieve gas supply pressures and thereby reduce natural gas prices.

Renewable energy has the added benefit of reducing exposure to environmental regulatory risk, which will be described below.

The treatment of "base case" gas prices and price uncertainty in the resource plans may have an impact on the degree to which these plans rely on renewable energy. The higher the base case forecast, and the more significant the expected price uncertainty, the more value a utility may place on renewable energy.

There is a high degree of uncertainty in forecasting gas prices. Therefore, it is important that resource plans evaluate different candidate resource portfolios under a wide range of natural gas prices and scenarios. There are a wide variety of approaches to applying gas prices to candidate portfolios. Few resource plans subject all candidate portfolios to stochastic gas prices; most only apply prices to a subset of "finalist" candidate portfolios. This is important because the later in the planning process this analysis is applied, the greater the potential for suboptimal results because low-risk portfolios may be screened out based on cost prior to this analysis.

In Mexico, in compliance with the Ley del Servicio Público de Energía Eléctrica (LSPEE) Act's least cost principle, the Comisión Federal de Electricidad (CFE) would pay renewables for their long-term avoided costs including the value of the long-term price stability.

Future environmental regulation is the second type of risk that can be reduced by increasing renewable energy in resource planning. Laws and regulations governing the environmental impacts of electricity are likely to change. Future requirements are likely to be more severe than they are today. Traditional air pollutants (SOx, NOx, mercury, particulate matter) may be more tightly regulated and new state or federal carbon regulations may be implemented.

Utility-owned fossil projects and long-term power purchase agreements may be subject to these downside regulatory risks. However, renewable energy is likely to be unaffected. Purchasing or owning renewable energy assets may reduce utility exposure to these environmental compliance risks. Therefore, those utilities that consider seriously the risk of future environmental regulations will prefer new renewable energy to new fossil generation, all other things equal.

Some states are requiring utilities to take this risk into account during resource planning. Utilities operating in Oregon under the jurisdiction of the Oregon Public Utilities Commission are required to consider the impact of a range of externality values on choice of portfolio. California utilities are required to apply carbon adders in resource planning and bid evaluation and to only allow purchases/investments in electricity generation that is at or below a specified emission level.

The way in which utilities evaluate and balance expected costs and risk of candidate portfolios is particularly important for renewable energy, which is generally characterized by low risk and potentially higher initial costs. Utility regulators understand that a utility's shareholders may have a very different set of customer risk preferences than its customers. In particular, in cases where fuel costs are automatically passed through to the customers in electricity rates, utility shareholders may see little shareholder value in mitigating fuel price risk. Utilities should, but rarely do, take into account customer preferences regarding cost-risk tradeoffs.

Public Benefit Funds

A public benefits fund (PBF, or "fund") is a revenue stream most commonly financed through an ongoing surcharge on consumer electric bills (e.g., a "green tariff"), but also occasionally established through lump-sum cash transfers required by state legislation or regulatory settlements. It is used to directly support projects and activities in the electricity sector that provide important public benefits or overcome market barriers. Roughly half the states in the US have established PBFs to promote investments in energy efficiency and/or renewable energy technologies.

States have typically created renewable PBFs with a common goal in mind: to help protect, preserve, and grow nascent renewable energy markets that might be in jeopardy as the electricity industry is restructured. Accordingly, many of these funds were established in states as they opened their electricity markets to retail competition. In some cases, state regulators have authorized the creation of renewable PBFs (e.g., New York, Pennsylvania). PBFs have also arisen from utility merger or environmental settlements (e.g., Illinois Clean Energy Community Foundation, Xcel Energy's Renewable Development Fund in Minnesota). An ancillary benefit of these programs is that they provide cost-stabilizing new sources of renewable energy.

Do these programs provide substantial quantities of renewable energy? Review of current practices seems to indicate that they do.

- The Energy Trust of Oregon (the non-profit administrator of Oregon's PBF) has set a goal to meet 10 percent of Oregon's electricity load through renewable generation by 2012. This translates into support for 450 average MW of new renewable generation; according to their annual report, the Energy Trust is nine percent of the way towards meeting this goal.

- The Massachusetts Technology Collaborative (the quasi-public administrator of Massachusetts' renewables PBF) has a goal of supporting the installation of 750-1000 MW of new renewable capacity by 2009. This goal overlaps considerably with the state's renewables portfolio standard that will require the construction of around 500 MW of new renewable capacity by 2009 and shows the complementary role PBFs and RPS can play.

- New Jersey's 2003 PBF annual report lists specific long-term goals of supporting 300 MW of new, in-state renewable capacity by 2008 and increasing in-state solar generation to 120,000 MWh/year by 2008.

In the United States, PBFs were originally created as a relatively simple way to equitably collect revenues to continue public benefits programs that might go unfunded in a restructured or competitive electricity industry. However, partly due to their success and simplicity, PBFs are now considered appropriate for either restructured or conventional utility systems. Although renewable PBFs have been important to the commercialization of renewable energy technologies in the United States, they are not a panacea for all barriers to renewable energy. While PBFs are able to support small, distributed generation technologies (e.g., rooftop PV), modest funding levels and an inability to offer power purchase agreements will limit the ability of PBFs to support large, utility-scale projects (e.g., wind farms). Therefore, PBFs should be deployed in combination with, rather than in lieu of, other policy approaches. Many states with both a renewable PBF and an RPS are finding that the two complement, rather than compete with, each other. In this way, PBFs can be an important element in a portfolio of policy approaches deployed to bring renewables into the mainstream.

Regarding the "potency" of the hedge value of renewables, it is important to state the assumption that the hedge value of renewable energy is only as effective as it is pervasive. A few solar panels on a skyscraper or even a few percent of utility supply from a renewable source is not going to work financial wonders for customers because the consumers will continue to be exposed to volatile fossil fuel prices for the vast majority of their needs. This point is not a criticism of the hedge value of renewables, it is just a reminder that scale is an important factor in delivering benefits.

IV. CASE STUDIES

CASE STUDY: California Renewable Portfolio Standard

California's RPS, enacted in 2002, is one of the most aggressive in the world. Originally, California's RPS required retail sellers of electricity to purchase 20 percent of their electricity from renewable resources by 2017. California subsequently accelerated this goal of 20 percent renewables to 2010, and set the state's 2020 goal at 33 percent. The California Renewable Portfolio Standard, along with other California policies and regulations on the electricity sector, provides California energy consumers with an increasing amount of price-stable and low-risk electricity, reducing California's dependence on natural gas and coal.

One analysis of the California RPS found that under a 33 percent RPS, gas prices would be reduced by an average of $0.02-0.06/MMBtu during the 2011-2020 time period.[34] A study by the Union of Concerned Scientists concluded that if average annual natural gas prices are $4 per million Btu through 2010, the original 20 percent California RPS would save consumers money, an amount reaching $918 million (in $2001) by 2010.[35] With natural gas prices of $5 per million Btu, the RPS would reduce consumers' bills even more, with an overall savings of $1.8 billion ($2001) by 2010.

One issue that was subject to much debate during the crafting of California's RPS rules was whether or not renewable energy certificates (RECs) from facilities outside California would be eligible, particularly if the RECs were unbundled from the underlying electricity. Unbundled RECs would reduce transmission costs by relieving the need to wheel power into the state, but would not convey the price stability benefits to California electricity customers. The state resolved to allow only RECs that are bundled with electricity that is imported into the state. While this may increase cost per MWh for Californians, it also will provide greater cost stability insurance.

[34] http://www.resource-solutions.org/lib/librarypdfs/Achieving_33_Percent_RPS_Report.pdf
[35] http://www.ucsusa.org/clean_energy/clean_energy_policies/powering-ahead-a-new-standard-for-clean-energy-and-stable-prices-in-california.html

CASE STUDY: The Solar Services Model of SunEdison

Jigar Shah, CEO of SunEdison, describes SunEdison's approach to meeting commercial customer needs:

> None of them want to own a power plant - it's just not core to their business. But they want solar power to lower energy costs through predictable pricing, and to improve the state of their environment. They want a solution with little or no disruption to their existing business.[36]

SunPower installs large commercial PV systems, with a customer list that includes Whole Foods, Macy's and Staples. Shah describes the price hedge benefits of SunEdison's contract with Whole Foods:

> We offered a contract that locked in electricity rates for 10 to twenty years. That removes volatility from their utility bills and provides a hedge against increasing rates in the electricity market. So that's a strong business rationale. There is literally no other solution on the market where you can lock in part of your electric utility costs for that length of time.

In 2004, Staples signed contracts for two 280 kW on-site solar PV projects at two of its distribution centers in California, covering about 10 percent of the facilities' loads. Staples signed a ten-year, fixed-price power purchase agreement (PPA) with SunEdison, with the option to renew in five-year intervals. The solar services model provides Staples with several benefits. The PV systems reduce the amount of power Staples buys from its retail electricity provider during the peak (and most expensive) hours of the day. They reduce the company's greenhouse gas emissions, helping Staples to meet one of its major environmental goals. The negotiated price for power is competitive with market rates, and the fixed price provides a hedge against retail electricity price increases. Furthermore, Staples avoids capital expenditures and maintenance costs for the PV system.[37]

Through the use of the solar services model, SunEdison provides customers with a no-hassle, fixed-price, long-term contract for solar power that can be cost-competitive with the customer's electric utility.

[36] http://marketinggreen.wordpress.com/tag/business-model/
[37] Information regarding the Staples contract with SunEdison excerpted from http://www.thegreenpowergroup.org/pdf/case_studies_Staples_2.pdf

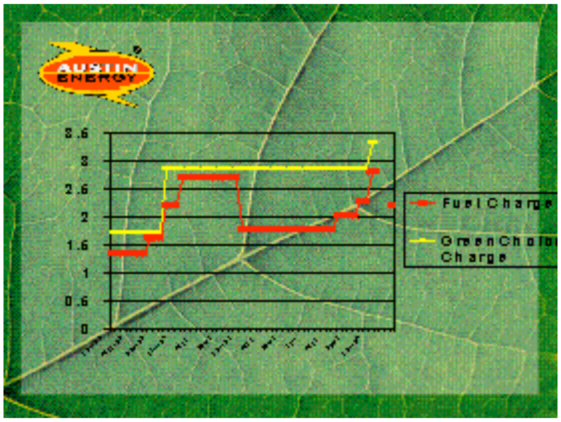
CASE STUDY: Austin Energy's Stable Rate Green Tariff

Austin Energy, a regulated municipal utility serving Austin, Texas, has one of the most successful Green Pricing programs, supporting more new renewables than any other utility program in the US. The National Renewable Energy Laboratory ranked it number one in sales in 2002, 2003, 2004, and 2005. Austin Energy launched the nation's first long-term (ten-year) fixed-price green power product for both commercial and residential customers in 2000. In designing the product, called GreenChoice®, Austin Energy locked in its own long-term fixed-price contracts for wholesale power from a variety of renewable energy projects. The price for that electricity will remain the same for the life of those contracts, allowing GreenChoice customers a way to hedge against fossil fuel price volatility.

Participants in the GreenChoice program see the electric bill standard fuel charge (currently 2.80 cents per kWh, but it is subject to fuel adjustment) replaced by a GreenChoice charge of 3.30 cents per kWh of electricity used. This replacement means that customers typically pay about one-half cent more per kWh to help support the renewable energy power provided by GreenChoice. The flat green rate provides customers with a price hedge against volatile fossil fuel prices. While fossil fuel prices are unstable, GreenChoice is offered at a fixed rate.

GreenChoice® is approximately 80 percent wind, 18 percent landfill gas, and two percent small hydropower, all of which is generated in Texas. An Austin Energy electric bill typically includes four different charges: fossil fuel, energy (overhead and transmission), peak demand, and taxes. The fossil fuel charge is typically variable. In the past, Austin Energy adjusted the fuel charge about once per year to reflect fossil fuel costs, but these adjustments became more frequent starting in 2000 with the volatility of natural gas prices. In the past four years, Austin Energy has had to increase its fuel charge several times in relatively short intervals. With the GreenChoice® product, though, the normal fossil fuel charge is replaced by a "green power charge" proportional to the amount of renewable energy that a customer chooses to buy.

The GreenChoice program was authorized by the Austin city council in 1999 and the program was launched in 2000. The initial rate was set at 1.7 cents per kilowatt hour. This rate fully recovered the costs of the original green power sources and was subsidized up to $1 million. Ten months after launching its program, Austin Energy had fully subscribed its initial 40 MW of new



renewable supply and had to contract for additional renewable supply. Austin's second offering was not subsidized and was priced at 2.85 cents per kWh. This represented the contract price for the wind and did not include congestion or ancillary service costs, which were not anticipated. At the end of 2003, Austin Energy increased the green power rate to 3.3 cents per kilowatt hour. This new rate covered the wind contract price, congestion costs and ancillary services costs. The new rate applies to new program subscribers only; current subscribers continue to pay the lower green power rates established in earlier phases of the program.At the same time, standard fuel charge rates were changing as well, making the difference between standard service and green pricing larger or smaller (See Table 1). At one point, the price of their renewable energy product was lower then the price of their default service, creating a "negative premium" for green power customers.

Austin Energy offered two batches of green power, each available in April 2001 but at different prices. The green power charge for Batch 1, which was subsidized by the City of Austin, was 1.7 cents/kWh. Batch 1 totaled 100,000 MWh/year and was fully subscribed six months prior to actual availability. Batch 2 totaled 260,000 MWh/year with a green power charge of 2.85 cents/kWh. Batch 2 was fully subscribed by January 2004, at which time Austin Energy began offering a third batch of green power.

In contrast to the fixed green power charges, Austin Energy's fossil fuel charges have ranged between 1.3 and 2.8 cents/kWh (*Figure 3*). These fluctuations generally follow changes in the price for natural gas, which is widely used in Texas for electricity generation and other industrial purposes. Austin Energy, in particular, uses natural gas for 30 percent of its power generation. As the fossil fuel charge rises above 1.7 cents/kWh, customers that signed up for Batch 1 green power pay less for renewable energy than they would for conventional energy. Even without the government subsidy, Batch 2 green power sells at near parity with conventional power and may be less expensive in later years depending on changes in natural gas prices.

The experience of IBM illustrates the hedge value of GreenChoice®. In March 2001, IBM signed a five-year contract for 5.25 million kWh per year from Batch 1. At the time, the company predicted that the green power would actually cost a premium of $30,000 per year, but opted for the purchase anyway due to three leading factors. First, the fixed-price nature of the contract provided a hedge in the face of unpredictable energy markets and IBM believed that the contract would pay off eventually. Second, the cost stability provided by the contract made it easier for the company to manage its energy budget. Third, buying green power was an opportunity for the company to reduce the greenhouse gas emissions associated with its business operations.

Austin Energy's fuel charge for conventional power spiked in 2001 and IBM saved $20,000 in its first year in the program. During 2002 and 2003, GreenChoice® cost slightly less than conventional power. The fossil fuel charge rose again in 2004 and IBM saved over $60,000 for the year. Given the business benefits it provides, GreenChoice® quickly has become the nation's largest green power program among regulated utilities, and is almost double the size of the second-largest program in terms of MWh sold per year. However, the Austin Energy approach has not yet been widely replicated. Only a handful of utilities in the U.S. have developed green electricity programs that protect customers from some variable charges. To build successful green pricing programs and meet the interests of commercial and industrial energy buyers, utilities should review the Austin Energy experience and consider approaches to integrating green power hedge value into their offerings.

Some information taken from Aulisi and Hanson. "Developing Next Generation Green Power Products for Corporate Markets in North America". http://pdf.wri.org/gpmdg_corporate_6.pdf

CASE STUDY: Public Service Company of Colorado 2003 Least-Cost Resource Plan

The 2003 Public Service Company of Colorado Least Cost Resource Plan is distinct from other integrated resource plans in several ways. First, the plan called for building 500 MW of new wind generation by the end of 2006. This plan was created before the Colorado Amendment 37, requiring a certain percentage of resources to come from renewable energy, was passed or put into effect. The inclusion of renewable energy was based on the value of including renewable energy within the PSCo portfolio. Secondly, while most utilities construct candidate portfolios by hand featuring resources that are regionally available and pass initial cost or performance screening tests, PSCo used a capacity expansion model to determine the combination of resources that would best meet their needs. Lastly, PSCo included the possible risk of increasingly stringent future regulations regarding sulphur dioxide, nitrogen oxides and mercury, a rare inclusion among IRPs.

The PSCo Least Cost Resource Plan was filed with the Colorado Public Utilities Commission on April 30, 2004. It included a planning horizon from 2003 through 2033 and an acquisition period of 2003 – 2013. The plan called for the utility to develop or acquire 3600 MW of electric generating power by 2013 to replace expiring contracts or meet additional demand. Eighty percent of this new generating capacity was to be competitively bid. The capacity was broken out as follows:

1. 500 MW of renewable energy, primarily from wind power;
2. Development of a 750 MW coal fired plant, of which Xcel was to own 500 MW; and
3. An all-source bid process to secure 2600 MW of new capacity from natural gas, other fossil fuel-fired generation, additional renewable energy, or demand reduction.

While most utility resource plans feature resources that pass an initial cost or performance screening test, the Public Service Company of Colorado 2003 Least-Cost Resource Plan utilized a capacity expansion model from the start to construct an optimal portfolio. Under this model, no candidate portfolios were developed. Instead, for each scenario examined, a capacity expansion model optimized a single portfolio based on user-defined market conditions and constraints. PSCo then imposed constraints on each of the potential new resources that it modeled due to the computational challenges of modeling hundreds of thousands of possible resource combinations available. PSCo limited the maximum amount of wind power that could be added in any year to 320 MW (modeled as four 80 MW projects), with a cumulative cap of 2000 MW over the thirty-year planning horizon. The model allowed two of the four candidate wind projects to be added even if not needed for capacity purposes, as long as the inclusion of such projects resulted in energy savings.

PSCo's initial plan ran a capacity expansion model under four different gas price scenarios - $3, $4, $5, and $6/MMBtu gas (2003$).[38] PSCo presents numerous optimal portfolios that vary depending upon assumptions about future market conditions and natural gas prices. Over the ten-year resource acquisition period (from 2003-2013), optimal wind power additions ranged from 240-1120 MW at an assumed $3/MMBtu real gas price, from 240-1440 MW at $4/MMBtu

[38] For price context, Henry Hub prices on Wednesday, January 31 2007 (the time of this draft) averaged $7.75 per MMBtu.

gas, from 640-1440 MW at $5/MMBtu, and from 1040-1440 MW at $6/MMBtu gas. Noting a degree of discomfort (in terms of reliability concerns and integration costs) with the amount of wind capacity called for at the upper limit of these ranges, PSCo imposed exogenous constraints on the model to make the optimization more tractable. These constraints play a significant role in determining the outcome of the modeling exercise. Ultimately, the utility chose to move forward with a solicitation for 500 MW of wind projects able to come on-line before the end of 2006. If acquired, the 500 MW, along with 222 MW of existing wind capacity, would increase wind's penetration on PSCo's system to about 11 percent of peak load.

As mentioned above, the cost and performance assumptions for renewable energy included in planning models will have a significant effect on whether or not renewable resources are developed. Costs can be divided into direct and indirect. Direct costs include busbar costs, which are defined to be the cost of wind power at interconnection, including levelized capital costs and operations and maintenance expenditures, as well as the value of the production tax credit. PSCo's levelized capital and O&M costs seem to be towards the higher end of the range.

The value that utilities place on the federal production tax credit (PTC) can have a significant effect on how renewables are treated in IRPs. While it appears that many utilities have understated the value of the PTC by accounting for it in a pre-tax rather than after-tax manner, PSCo explicitly modeled this part correctly. In its initial IRP filing, it simply assumed a busbar cost for wind that was inclusive of the PTC (rather than breaking the PTC out). However, in its settlement with stakeholders, PSCo calculated the cost of additional wind capacity assumed not to benefit from the PTC by starting with the PTC inclusive busbar cost and backing out the value of the PTC yielding an equivalent "no-PTC" busbar cost. Unfortunately, PSCo overvalued the PTC in this calculation, which led to a "no-PTC" busbar cost that was too high relative to the PTC-inclusive cost, thereby hurting wind's competitiveness in this analysis.

Indirect costs include transmission and integration costs. The PSCo plan anticipates that wind will be developed within its own control area and does not reflect any transmission costs. Wind integration costs represent the impact of incorporating, as available, wind power into the grid. PSCo estimates integration costs as $2.50/MWh for the first 480 MW at nine percent of peak load wind penetration and $7/MWh for the next 320 MW at 14 percent of peak load wind penetration. The initial $2.5/MWh cost estimate was based on an average of literature review. In settlement with stakeholders, the cost increased for the next 320 MW based on an assumption that costs will increase with higher levels of penetration.

The most rigorous method for determining a project's contribution to meeting capacity needs is effective load carrying capacity (ELCC). PSCo did not use ELCC to determine capacity in its 2003 LCP; instead, it used a method adopted by the Mid-Continent Area Power Pool (MAPP) to assign a 10 percent capacity credit to wind in Colorado. The period of interest is the peak hour plus three contiguous hours during the peak month of the year, and the median hourly wind output during this period sets the capacity value. It appears that this value may have been on the low side.

In determining the risk posed by future environmental regulation, PSCo considers the possibility of both carbon regulation and regulation for other pollutants. This seems to be rare in most IRPs, in that many utilities look at carbon regulation only and ignore potential future regulation for other pollutants. For its initial IRP, PSCo assumes a cap and trade with a cap year of 2000, a start year of 2009, and three scenarios with \$0/ton, \$5/ton, and \$9.9/ton with no probability weighting for any scenarios. The PSCo settlement plan assumes cap and trade, with cap year of 2000, a start year of 2009, and a base case model with 100 percent probability at \$7.20/ton. PSCo considers the possibility of increasingly stringent future regulation of criteria pollutants (SOx, NOx, mercury, particulate matter) in its original resource plan. Assumed cost of complying = SO2: \$796/ton (levelized 2003 \$/ton); NOx: \$796/ton; and Mercury: \$9,954/ton.

Resource Acquisition Process

In February 2004, Xcel Energy announced the construction of a new 750 MW coal-fired generating unit at an existing facility, Comanche Station in Pueblo Park. In April 2004, PSCo filed the 2003 Least Cost Resource Plan. The Colorado Public Utilities Commission (CPUC) consolidated review of the Comanche coal plant with the Least Cost Planning (LCP) and wind power plant review. In August 2004, the CPUC approved the RFP process for the 500 MW of renewable energy. PSCo requested an accelerated decision on the renewable energy in order to be able to take advantage of the federal production tax credit. Once the RFP process was approved, PSCo issued an RFP for up to 500 MW of wind to be on-line by the end of 2006. When the PTC was extended only to the end of 2005, PSCo accelerated the projects to come on-line by the end of 2005. They short-listed three projects totaling 400 MW of new wind generation, but in late March 2005 signed contracts with only two projects, totaling 129 MW.

During the review process for the LCP and Comanche station plant, 28 organizations, agencies, and other groups intervened in the consolidated hearings. The CPUC held three weeks of public hearings on the LCP in November 2004. On December 17, 2004, the Colorado Public Utilities Commission approved an all-inclusive settlement agreement regarding the Least-cost Resource Plan. The settlement agreement was endorsed by a variety of parties, including the CPUC staff, Colorado Office of Consumer Council. Southwestern Energy Efficiency Project, Sierra Club, Environmental Defense, Western Resource Advocates, Tri-State Generation and Transmission Association, and others. Under the settlement, PSCo would move forward with the building of the new Comanche plant, but would install state-of the art emissions reduction equipment on all generating units at the Comanche Generating Station, reducing total sulfur dioxide and nitrogen oxide emissions at the station despite increasing total production. The company would also expand energy conservation programs by undertaking best efforts to acquire 320 MW of total demand reduction over 10 years, accelerate a feasibility study of additional renewable energy resources, work with environmental organizations to identify programs to reduce GHG emissions, provide donations to local Pueblo community to reduce diesel bus emissions from school districts, fund mercury reduction efforts at a local steel mill, and participate in Pueblo sustainable economic development discussions.

In late February 2005, PSCo issued an all-source RFP for 2500 MW from dispatchable, non-dispatchable and demand-side resources. Renewable energy is eligible to compete in this solicitation. In December 2005, PSCo announced intent to acquire 775 MW of additional wind generation to be in service by the end of 2007, 1300 MW of existing and new natural gas generation to be in service between 2007 and 2012 and 30 MW of energy efficiency and conservation from third parties. Xcel committed to spend \$196 million to achieve 320 MW of energy efficiency and conservation through 2013 with third party or company-sponsored programs.

If the proposed wind energy projects are successful, Xcel Energy would become the largest provider of wind energy to customers in the U.S. and would also meet non-solar Amendment 37 requirements for 2015 – seven years early.

As of October 2006:

- Construction continues on the 750 MW Comanche 3 coal-fired generation unit.
- The All-Source RFP Bid Evaluation process for 2007-2012 is complete. PSCo has executed power purchase contracts for three wind facilities totaling 775 MW and five gas-fired facilities totaling 1300 MW. Therefore, PSCo has completed contracts for resource additions to meet customers' forecasted electricity demand through 2012.
- Continuing evaluation and negotiation of bids offered for 2013.
- Negotiating contracts for a 3.2 MW LFG facility and a 0.22 MW hydro facility.

CASE STUDY: Contract for Differences – City of Calgary, Alberta, Canada

The concept of green Contracts for Differences (CFD) has been put into practice in Alberta, where wind- and biomass-based CFDs have been structured in the wake of market deregulation. Wholesale electricity market restructuring began in Alberta in 1996. In 2000, power prices spiked, at one point reaching a 500 percent increase over prices at the start of the year. Price volatility was hitting power markets throughout western North America due to a combination of factors, including the California electricity crisis, natural gas price increases, capacity and transmission issues, and gaming by market participants. As Alberta moved to full deregulation for both wholesale and retail markets in January 2001, energy buyers understood the value of hedging against electricity price volatility.

In September 2001, Calgary Transit of the City of Calgary began a 10-year green CFD based on wind power. The wind generator is VisionQuest, a division of the TransAlta power company. In addition, the retail power supplier, ENMAX, serves as an intermediary owing to its existing customer relationship, although it has no risk exposure in the contract. Calgary Transit partnered with VisionQuest to develop "Ride the Wind!," a program that uses wind-generated electricity to power its commuter CTrains.

There are 12 windmills located in southern Alberta that generate the wind power. The amount of power equivalent to that used by the CTrain is sent to the main power grid. The CFD covers a load of 26,000 MWh per year and is indexed to Alberta's spot electricity market (there is only one spot market in the province). The strike price for the contract is in the range of 7 cents Canadian per kWh. Since contract inception, the spot price for power has fluctuated above and below the strike price, meaning both parties have made and received payments.

Although the CTrain itself does not produce CO2 emissions, the supply of electricity used originally for CTrain traction power was supplied by coal- or natural gas-powered facilities that do produce greenhouse gases. Using wind-generated power, CTrain has been able to reduce CO2 emissions by 26,000 tonnes annually. As the CTrain lines are extended, the savings in emissions will also increase. It is expected that the "Ride the Wind!" program will increase power costs by less than one-half of one cent per passenger.

Since the implementation of the "Ride the Wind!" initiative in 2001, Calgary Transit has been the proud winner of two prestigious awards. In 2001, it won a Federation of Canadian Municipalities CH2M HILL Sustainable Community Award for its leadership in renewable energy. Calgary Transit was also the recipient of a 2001 Pollution Prevention Award in the innovations category, presented by the Canadian Council of Ministers of the Environment, and a 2004 Corporate Recognition Award from the Canadian Urban Transit Association (CUTA).

The CTrain is now 100 percent emissions free. It is the first public light rail transit system in North America to power its train fleet with wind-generated electricity[39].

[39] *Some information sourced from Calgary Transit web site,* *http://www.calgarytransit.com/environment/ride_d_wind.html*

V. Program Recommendations/Conclusion

Renewable energy is best known to the public for its environmental benefits. However, fossil fuel price increases in recent years have drawn attention to renewable energy as a price-stabilizing technology. Following is a summary of key points on why renewable energy is a price hedge, and how electricity providers and their customers can tap into that hedge benefit.

- Fossil fuels have experienced, and continue to experience, unpredictable and volatile prices. In order to lock into long-term, fixed-price contracts for fossil fuels, a considerable premium must be added to the supply contract.

- Renewable energy is mainly sourced from free fuels such as wind, sunshine, waterways, and geothermal sources.

- There is little correlation between forecast and actual prices. The problem is such that we have both high volatility and little ability to forecast.

- Coal prices have been easier to accurately forecast, but coal is associated with major environmental and regulatory risks. It is difficult to predict how coal could be constrained by potential greenhouse gas regulations or how this could affect prices.

- Utilities and electric service providers can tap into the price hedge value of renewables by:
    - Basing their evaluation of future natural gas prices not on forecasts but on actual forward prices.
    - Including future regulatory risk as a factor when evaluating non-renewables.
    - Including renewable energy in IRP resource plan analysis or as a critical part of the supply portfolio.
    - Buying renewable energy or renewable energy certificates (RECs) through Contracts for Differences.

- Individual electric customers can obtain the price stability benefits of renewable energy by:
    - Installing on-site renewable energy generation.
    - Buying renewables though a pricing structure that is based on the long-term price of the renewable energy (and is not pegged to fossil fuel prices).

Renewable energy is already making a difference in providing price stability benefits, not only for renewable energy consumers, but for all energy consumers. According to the American Wind Energy Association, by the end of 2006 wind energy use will save over 0.5 billion cubic feet (Bcf) of natural gas each day, relieving some of the current supply shortages.[40] As fossil

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[40] http://www.awea.org/pubs/factsheets/EconomicsOfWind-Feb2005.pdf

fuel prices appear to be on a continued upward price trend, and as price spikes have been the norm in the industry, we expect renewable energy to be an increasingly attractive option for utilities and individual electricity consumers.

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ELECTRIC POWER RESEARCH INSTITUTE

Thinking About Generation Diversity – Part 2

Electric Power Plant Asset Portfolio Valuation and Risk

3002003949

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Technical Update, March 2015

EPRI Project Manager

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ABSTRACT

In recent years, large amounts of natural gas-fired power generation capacity have been added to the nation's portfolio of power generation assets. In addition, a number of analyses and market projections imply that this trend will continue for a variety of reasons, including large and growing supplies of natural gas due to the "shale boom" along with commensurate low natural gas prices and imposition of increasingly stringent environmental regulations related to coal-fired power generation. This potential increased reliance on natural gas to meet our nation's electricity needs is causing some concern among electric industry executives, electric power generation planners, electricity customers, and electricity market regulators.

Many market participants and observers are keenly aware of recent periods during which the electric sector in the United States became heavily reliant on a single generation technology for the dominant share of electricity production and/or capacity additions, and they remember the problems that resulted from this situation. These concerns have led some observers to develop a concept referred to variously as "generation portfolio diversity" or "generation fuel diversity." This concept implies that it is valuable to have a broad diversity of power generation technologies and fuels included in the mix of national and local power generation sources.

In the past, generation capacity expansion decisions have been evaluated based on their impact to company profitability in the case of non-regulated generation companies or the cost of serving customers for regulated companies. These criteria still apply and are appropriate to be used to address capacity expansion in the face of concerns related to power generation diversity.

This report describes analytic methods that can be used by electric industry participants to improve decision making with regard to new generation capacity additions. It builds upon a 2013 Electric Power Research Institute (EPRI) report (3002001214) that argued that the decision problem faced by electricity planners pertaining to "generation diversity" is similar to those faced in the past related to "capacity expansion." The analysis approach described in this 2013 EPRI report was analogous to the use of portfolio diversification strategies used to increase expected gains and minimize risks in an equity stock portfolio.

In this report, we describe the results of two different types of generation expansion analyses we conducted in 2014. First, we analyze how different types of new capacity may impact the levelized cost of electricity associated with potential development of a single new power generation asset. Second, we analyze the potential addition of new generation capacity to an existing portfolio of generation assets, and track the profitability of the assets as they participate in a regional power market. For this analysis, EPRI evaluated what types of changes in the underlying economic and regulatory assumptions might alter the decision in the base case to build new natural gas-fired generation and instead invest in other generation technologies.

Keywords

Fuel diversity
Generation expansion
Generation planning
Generation portfolio diversity
Natural gas power generation

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1
THE GENERATION DIVERSITY CHALLENGE

In recent years, the electric power sector in the United States has added large amounts of natural gas fueled capacity to the nation's portfolio of power generation assets. In addition, a variety of analyses and market projections imply this trend will continue for a variety of reasons, including large and growing supplies of natural gas due to the "shale boom" along with commensurate lower natural gas prices, and imposition of increasingly stringent environmental regulations associated with coal-fired power generating facilities.

The potential increased reliance on natural gas fired power generation to meet our nation's electricity needs is causing some concern among electric industry executives, electric power generation planners, electricity customers, and electricity market regulators. Many of these market participants and observers are aware of recent times in history in which the U.S. electric sector became heavily reliant on a single technology for the dominant share of electricity production and/or capacity additions and the problems that may arise out of this situation.

Electric power companies have many technology and fuel options available to generate electricity. These options include well known technologies such as coal, nuclear, various natural gas fueled power plants and renewable technologies, such as wind and solar. The industry has a long history of choosing from among these technologies to add capacity to serve demand growth and replace retired capacity. Recent drops in the price of natural gas, and to some extent increases in the cost of coal, have made natural gas fueled generating units more competitive for all durations of electric loads. In addition, the natural gas fueled technologies put less capital at risk, can be brought on-line in a shorter time frame, and appear to face less risk from tighter environmental regulation of emissions such as SO_X, NO_X and CO_2 than coal-fired technologies. Thus, at current natural gas prices, natural gas-fueled generation capacity appears to be an attractive choice for new capacity in many circumstances.

Many companies, regulators and industry organizations are concerned about possible future lack of "diversity" in the generation mix, particularly over the longer term, if all new power plants are fueled with natural gas. These concerns arise based on the old dictum against "putting all of your eggs in one basket." This perception of risk is based on many factors. Fuel costs are highly uncertain and price swings can dramatically change the relative economics of the competing power generation technologies. In addition, different technologies can experience technology-specific impacts that change their competitiveness.

Throughout this report, we use the term "generation diversity" to include both diversity in the underlying technology used to generate electric power and the concomitant diversity in the fuels used to fuel these generation technologies. In short, generation diversity is a broader term that encompasses fuel diversity within it.

Issues Associated with Reliance on a Single Generation Technology

A reliance on a single fuel or electric generating technology can lead to a variety of issues. Electric system operations can drive up the demand for the specific fuel needed by the generation technology, such as natural gas or coal, causing the price of the fuel to jump unexpectedly. Reliance on a single generation technology potentially can lead to a situation in which fuel price volatility can have very large impacts on company operating costs and consumer electricity costs.

Increasing reliance on a single electricity generation technology also can lead to a shortage in the marketplace for the skills and capabilities needed to bring new generation units of the technology online. This scarcity of skilled labor and equipment can drive up the cost of developing and building new generation units, and lead to longer lead times to bring new units online.

"Common mode" failures associated with a specific technology can cause problems if use of the specific technology is widespread. These kinds of operating failures can come about as a result of ongoing normal operations or changing environmental and safety regulations. One recent example of this kind of "common mode" failure occurred during the 2014 Polar Vortex in which a large number of natural gas-fired generating units in the Northeast, Mid-Atlantic and Midwest regions of the United States experienced unforeseen outages at the same time due to the extreme cold temperatures that affected these regions. Readers should understand that all technologies face such technology-specific risks. For example, coal deliveries depend on river-based transportation systems that also are subject to interruption due to freezing and rail-based systems that may have reduced delivery capacity due to capacity constraints caused by competition from other loads, particularly the delivery of oil from recently developed oil fields.

Any or all of these issues have the potential to occur if our nation's electric generation portfolio becomes overly reliant on natural-gas fueled generation technologies like combined cycle natural gas plants (NGCCs) or combustion turbines (CTs).

The Value of Generation Portfolio Diversity

These concerns have led some industry observers to develop a concept referred to variously as "generation portfolio diversity" or "fuel diversity." Fuel diversity typically refers to the specific fuels that may be burned to generate electricity, such as coal, fuel oil or natural gas. "Generation diversity" refers to the diversity of power generation technologies that can be used to generate electricity, such as NGCC plants or coal-fired power plants. Because different generation technologies are associated with different types of fuels, these two terms often are used interchangeably. The concept of generation diversity implies it may be valuable to have a broad diversity of power generation technologies included in the mix of national and local power generation.

The purpose of this report is to build on work completed by EPRI in 2013 that described analytic methods that can be used by electric industry participants to understand operational and financial risks associated with operating our power systems, and to improve decision making with regard to new generation capacity additions. In our 2013 report, we argued the decision problem faced by electricity planners with regards to "generation diversity" is analogous to those faced in the past related to "capacity expansion." The analytic approach used in our 2013 report was analogous to the use of portfolio diversification strategies to increase the expected gains and minimize risks in an equity stock portfolio.

In the past, generation capacity expansions decisions have been evaluated based on their impact to company *profitability* in the case of non-regulated generation companies or so-called

Independent Power Producers (IPPs), or the *cost of serving* customers for regulated companies, such as Investor Owned Utilities (IOUs). In 2013, we argued these criteria still apply, and are appropriate to be used to address capacity expansion in the face of concerns related to power generation diversity. In this report, we apply our analytic approach to several illustrative portfolios of existing power plant assets to see how they might perform under various future technology and market assumptions.

Generation Diversity as a Risk Management Problem

The term "diversity" implies that a diverse generation capacity mix has value. Ranking the value of building and operating different generation technologies based on a single future scenario, or state of the world, will produce different values associated with the individual power generation technologies on a stand-alone basis. The potential value of having a diverse portfolio of generation assets arises because the value of each kind of power generation technologies differs depending on which potential "future" is realized.

Because the future is uncertain, and many different "futures" may evolve from today's vantage point, it is necessary to address generation portfolio diversity as a risk management or insurance problem. An effective way to manage these risks is to construct a portfolio of power generation capacity additions that performs "best" across the multiple expected future scenarios. This implies that a key feature of a robust analysis methodology is that it will recognize the potential existence of many possible future scenarios that give rise to the risk management problem.

It is possible to analyze in a quantitative way the expected performance of candidate capacity expansion plans across a suite of possible future scenarios. One analytic approach designed to address the generation diversity challenge is fully described in EPRI's 2013 report[1], and its use is demonstrated in this report. This analysis approach is based on the explicit quantification of the *financial risks* and *expected returns* that may be associated with pursuing different courses of action in light of explicit consideration of the future uncertainty in important factors that affect the electricity industry.

The use of scenarios makes it possible for the overall quantitative analysis to be used to estimate the performance of a proposed generation expansion plan under a wide range of circumstances. History has proven that predicting the future environment in which electric companies may operate is very difficult, if not impossible. Admitting there are a wide range of possible future outcomes, and explicitly tracing the impacts that may result from the realizations of different potential future scenarios, is both more realistic and insightful.

While scenario-by-scenario results can help a company to understand the implications of different futures, another method might be to consider assigning a *probability* to each potential future scenario. This allows the analysis to be used to calculate summary statistical measures of system performance, such as the ***mean*** (average) and ***standard deviation*** (a measure of outcome spread or variation). These summary statistics characterize the probability density function for

[1] *Thinking About Generation Diversity: Electric Power Plant Asset Portfolio Valuation and Risk.* EPRI, Palo Alto, CA: 2013. 3002001214.

different configurations of a proposed system expansion plan. The assignment of probabilities to different future scenarios is described in more detail in section four of this report.

In the analysis described here, the mean for a specific capacity expansion plan is a measure of the expected financial return while the standard deviation measures financial risk. Figure 2-1 is an example of a probability density function. As shown in Figure 2-1, the generation expansion plan illustrated here has a mean present value revenue requirement of ~\$6.5 billion and a 95th percentile revenue requirement of ~\$8.25 billion.

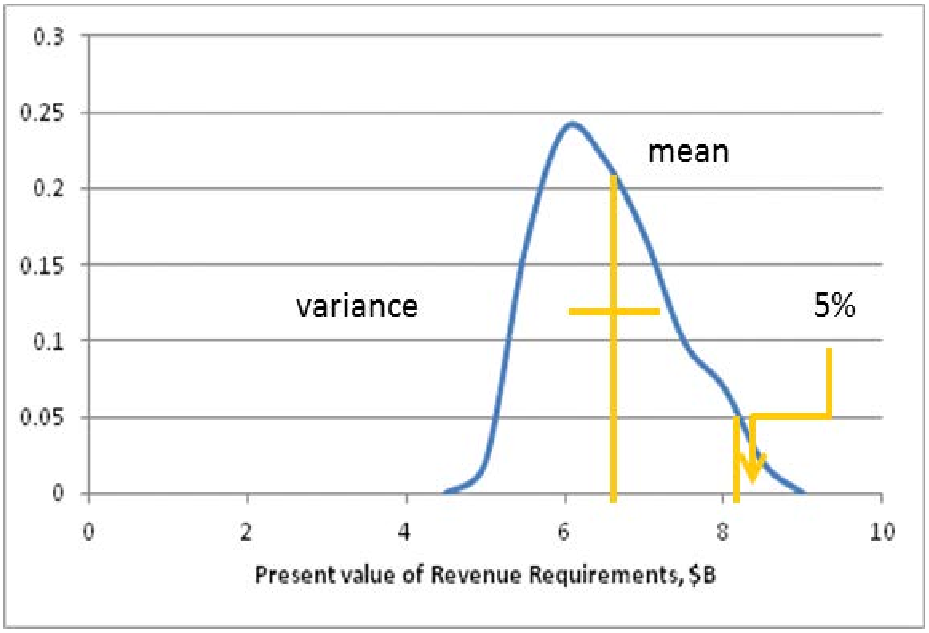

Figure 1-1
Probability Density of Expected Utility Revenue Requirements

Producing a result like the one shown in Figure 1-1 usually requires a quantitative model to be developed of the generating entity. The first step in conducting this type of modeling is to define the uncertainty associated with the model inputs used in the model. Some analysis is based on describing the uncertainty for an assumption with a well-known probability density. For example, the cost of an NGCC power plant could be represented by a normal distribution with a mean of \$1,200 per kilowatt with a standard deviation of \$100.

Metrics to Measure Key Output Values

It is important to select a key measure, or a few selected measures of system performance, to calculate statistically. Not all organizations will choose the same key measure(s) of performance. The management of many companies, as well as regulators, may be inclined to select economic or financial measures to calculate.

For example, a regulated electric utility likely would choose to measure the required revenue they need to obtain from their customers to provide the company with an expected rate of return. A state public utilities commission (PUC) might be interested in how a proposed portfolio of power generation assets might impact company revenue requirements and expected future electric rates to be charged to customers. An IPP may be more interested in quantifying a measure of the profitability of their portfolio of generating assets.

Companies might want to view other results that may be of interest. An organization that is focused on reducing its environmental footprint might want to measure specific types of air or water emissions at a target date in the future. For example, estimating the potential impact of new generation options on the amount of company greenhouse gas (GHG) emissions in 2020 might provide a company with some indication of how that portfolio may fare against potential future regulations that target GHG emissions.

Many companies are likely to be interested in focusing their analyses on actions or decisions they can take that will directly influence the outcomes they are interested in measuring. This implies companies should try to include specific decisions or policies they may adopt or be subjected to, when the company embarks on analysis of future generation options. By doing this, companies can focus on the potential impact their decisions may have on output metrics they consider critical, such as impacts on customer rates, emissions, and profitability.

To do this, an analysis of a company's generation diversity would need to be designed to test the attractiveness of alternative actions that can be taken by the company in each of the scenarios analyzed in the study. By doing this, a company can develop statistical measures like those shown in Figure 1-1 associated with each of the alternative actions tested for each of the possible future scenarios. The "best" course of action to be taken by the company would then be the one that yields the most attractive probability density function, based its mean and standard deviation.

In the "stand alone" capacity expansion plan analysis described in section three, the key metric we use to determine the "best" new generation plant to build on a stand-alone basis is the expected levelized cost of electricity (LCOE). This is not the only measure that could be used to evaluate the potential net benefits of developing a new stand-alone power plant. For example, one could focus on measures of expected profitability, such as the expected net present value of the cash flows associated with the development of a new power plant.

In the "portfolio" analyses described in section four, the key metric we use to determine the "best" incremental addition to an existing portfolio of power generation assets is the change in expected mean levelized cash flow measured in dollars per year over the expected life of the proposed new power generation asset.

Figure 1-2 illustrates this verbal description. The analysis is investigating the suite of actions contained in the set of boxes at the left of the figure. These actions must be tested on the scenarios defined in the set of boxes at the bottom of the figure. Each of these scenarios is defined by the inputs to the model or calculation method. The scenarios define different futures by altering the values of the inputs. Each scenario has a probability or likelihood that it occurs, including the possibility that each scenario is equally likely to occur. The next box to the right is the model used to calculate the criteria or the criterion value(s). Finally the value of the criteria for each scenario is weighted by its scenario probability to produce the probability density for each of the actions.

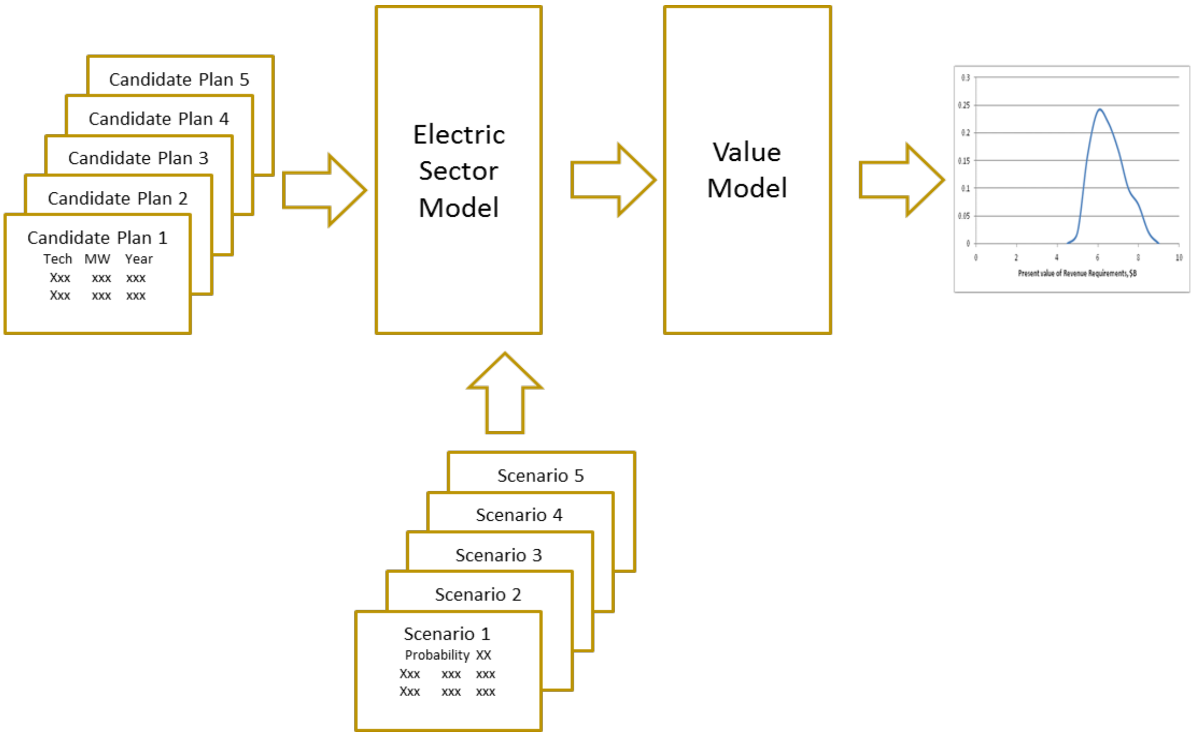

Figure 1-2
Illustration of How to Calculate the Probability Density of Key Values

Making the Analysis More Realistic

Some simplifications to the methods described in EPRI's 2013 report were used in the analysis described here. This approach was designed to clarify the kinds of analyses that can be performed and the results and insights that can be obtained. This subsection suggests approaches that can be used to increase the accuracy of the analysis by using common, but more sophisticated methods.

The analyses described in sections three and four include simple representations of the timing and dynamics of generation asset portfolio performance. The analyses effectively isolated a "typical year" and estimated the LCOE or profitability and the uncertainty in that profitability. Most companies that have significant investments in generating capacity use models that explicitly represent time. These models take as inputs the existing capacity at the start of the time horizon. They represent how the loads (for a cost-based analysis), or the market (for profit maximizing companies), may evolve over time. This requires estimates of the cost of commodities such as generating fuels. The cost of adding new generation capacity also is required.

The model can evaluate different portfolios of capacity expansion options. The inclusion of detailed timing allows consideration of subtle tradeoffs that cannot be made with the simplified, typical year structure used in many analyses. For example, the relative competitiveness of technologies can change over time as fuel prices escalate, as recently-introduced technologies accomplish learning through experience, and as new technologies are developed.

Regulated companies that are trying to minimize customer revenue requirements associated with serving a projected customer load often will use sophisticated production costing models to calculate the variable cost of generation. In addition, they use sophisticated financial models to estimate the fixed cost of service.

Although many such models exist, EPRI has developed a widely used tool called the *Electric Generation Expansion Analysis System (EGEAS)* to perform the calculations for a cost driven company.[2] This model fits the description above. EGEAS is a well-respected modular production costing and generation expansion software package. It is used by electric utility planners to develop and evaluate integrated resource plans, avoided costs, and plant life management plans. It also has modules that accommodate demand-side management options, and facilitate development of environmental compliance plans. It also calculates a least-cost expansion plan for the given inputs for a scenario. By driving EGEAS through analysis of a suite of scenarios with associated probabilities, an analyst can provide cost results that can be used to produce the probability density function shown in Figure 1-1.

Section three discusses EPRI's analysis of how different types of new electric power generation capacity may impact the expected LCOE associated with potential development of a *single new power generation asset*. This first case explores the economic decision making associated with building a single new power plant on a stand-alone basis, where the new plant is not being added to an existing portfolio of generation assets.

Section four explores two different types of economic analyses that can be used to evaluate a decision to add new generation capacity to an existing portfolio of generation assets, and track the profitability of the assets as they participate in a regional power market. These two types of analyses are referred to as "open loop" and "closed loop." These terms and the associated analyses are more fully described in section four.

This report builds on EPRI's work on this topic in 2013 that argued the "diversity challenge" is basically the same problem as "capacity expansion" – a challenge the electric power industry has faced since its inception. Capacity expansion plans can be evaluated using the same quantitative criteria that have been used traditionally by power planners and economists. The generation diversity challenge is a risk management challenge, so analysis of the value of diversity must rely on careful construction of scenarios and evaluation of candidate capacity expansion plans over the set of foreseeable futures. Adding a probability to each scenario adds rigor and provides additional insights into capacity planning.

This project built upon the research foundation provided in 2013 to provide further insights about key factors that may change decisions about the building of new generation capacity away from natural gas towards other potential generation sources. For example, how would economic conditions have to change to make investing in gas-fired generation a comparably poor choice as compared to investing in wind power plants at existing fuel prices? How would fuel prices need to change to encourage a company to build something other than natural gas-fired generation?

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[2] Electric Power Research Institute, *Electric Generation Expansion Analysis System (EGEAS)*, www.epri.com. Available online at: http://membercenter.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001016192

The goal of Phase 2 of this research was to gain further understanding of the financial value and risks associated with generation diversity, based on analysis of two scenarios: (i) the potential "green field" development of a *single power plant* when there is no other existing generation asset in the portfolio; and, (ii) the potential addition of new capacity to an existing electricity generation *portfolio* comprised of multiple generation assets.

We urge readers to use caution when reviewing the results of our analyses shown in this report*, *and to avoid developing strong conclusions based on the illustrative, quantitative analysis described here. The assumptions used to conduct our analyses were selected to be a reasonable representation of that state of today's electric power business and the near-term future. However, these assumptions differ by region, and can quickly change over time, leading to very different results. The examples described here are **illustrative only**. We constructed them to inform readers about one way to study generation diversity, and to familiarize them with some of the kinds of insights these analytic methods can help to elucidate.

2013 Report Findings

The findings of EPRI's 2013 technical update report included:

- Fuel diversity is not an end in itself, but a potential way to increase the performance of the electric system.
- Electric companies should pursue important goals that increase system performance. These goals may include the cost of electricity.
- Other goals also are important, including reducing the risk that the cost of electricity will increase unexpectedly, and complying with all regulations related to health, safety and the environment.
- Fuel diversity should be the result of a company's capacity planning.
- Capacity planning must consider both risks and economic rewards.
- Capacity planning benefits from analyzing the uncertainties related to the problem.

2014 Project Goals

The 2014 project builds directly on the foundation created by our 2013 research. First, we analyze the LCOE for different types of new capacity associated with the potential development of a single new power generation asset. This first case explores the economic decision making associated with a decision to build a single new power plant on a stand-alone basis. The goal for this analysis is to explore what key factors in the economy or regulatory environment might encourage development of different types of new power generation capacity. To accomplish this analysis, EPRI developed a "Base case" analysis to illustrate the current situation in which incremental natural gas power generation appears to dominate generation expansion decisions based on "conventional" assumptions about key variables such as future natural gas prices, coal prices, environmental and other factors.

Next, we analyze the potential addition of new generation capacity to an existing *portfolio* of generation assets, and track the profitability of the assets as they participate in a regional power market. In this case, EPRI evaluated what types of changes in the underlying economic and regulatory assumptions might alter the decision in the Base case to build new gas-fired generation and instead invest in other generation technologies. Key variables evaluated in this report include: (i) changes in future natural gas prices: (ii) potential regulatory changes that may require significant carbon dioxide (CO_2) emissions reductions from the electric sector; and (iii) potential changes in the cost and performance of key underlying power generation technologies.

We evaluated the potential addition of incremental generation to three different example portfolios of existing generation assets: (i) a coal generation dominated portfolio; (ii) a natural gas dominated portfolio; and, (iii) a diverse generation mix characterized by a large portion of renewable resources and relatively “cleaner” burning fossil-fired power plants.

These analyses illustrate methods that may prove helpful to electric companies considering new capacity additions, and provide insights into capacity expansion choices in today’s world.

2
TODAY'S ELECTRIC CAPACITY SITUATION

In recent years, U.S. natural gas supplies have grown rapidly and prices have been low relative to coal prices, leading to changes in the dispatch order of existing electric power plants. This situation has resulted in some previously "base load" coal-fired power plants cycling more often, and natural gas plants that previously operated only at peak times now are operating with higher capacity factors. At the same time, the recent adoption of new environmental regulations by the U.S. Environmental Protection Agency (EPA) has resulted in some companies retiring some existing coal-fired generating units rather than retrofit them with pollution control equipment.

In this "new" dispatch environment, it has been reported that electric companies are re-evaluating their long-term generation options and capacity expansion plans, and are considering becoming more heavily reliant on new natural gas-fired power plants to meet current and expected future electricity demand.[3] However, some experienced generation planners and industry observers are wary of the potential heavy reliance in the future on natural gas based power generation, and believe it is important for companies to maintain a diverse generation portfolio that relies on a mix of fuels and generation technologies.

Power generation technologies that utilize natural gas as a fuel, such as NGCCs and CTs are viewed by some industry participants as preferred choices for new generation capacity. Recent analysis conducted using EPRI's REGEN model suggests much of the remaining capacity additions expected in the next decade are likely to be made up of new natural gas-fired generation units and renewable resources, mostly wind and some solar power generation technologies, as shown in Figure 2-1.

The amount of new renewables is an important consideration in understanding the risks of capacity expansion plans that rely heavily on natural gas-fueled generators. EPRI's analysis using the U.S. REGEN model suggests a substantial amount of new power generation capacity is expected to be built in the U.S. between 2010 and 2050, and that this new capacity is likely to be comprised of new wind power plants, new nuclear facilities and incrementally new natural gas generation facilities. Many of these new natural gas fired facilities are expected to replace older facilities that will be retired, as shown in Figure 2-1.

Energy versus Capacity

The capacity of new power plants, measured in megawatts (MW), can be misleading with regards to the relative roles of natural gas and renewable resources in generating electric energy (measured in megawatt hours (MWh) needed to meet electricity demand.

Wind and solar power plants are constrained by the available fuel resources – wind and sunlight – that are required to produce electricity. As a result, these renewable technologies are referred to as "non-dispatchable." Many wind power plants generating power today, or that are being

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[3] "Natural Gas Taking Off In Power Sector," American Oil and Gas Reporter. Online at: http://www.aogr.com/web-exclusives/exclusive-story/natural-gas-taking-off-in-power-sector . Accessed February 27, 2015.

developed, operate with capacity factors of 20-40% on average. In contrast, individual natural gas fueled power plants can generate electric power 90-95% of the year if they are profitable to run at any given hour and so are "dispatched." In practice, even when gas prices are comparatively low, it is rare for the average capacity factor for a fleet of NGCC to exceed 75-80% capacity factors. The dispatch of natural gas-fired power plants depends on many factors, including fuel prices, heat rates, variable operations and maintenance costs, emissions costs and other factors. It is important to understand that equal amounts of generation *capacity* of natural gas fueled and renewable technologies may not generate equivalent amounts of electric *energy* to serve customer needs for power due to differences in fuel availability and dispatch.

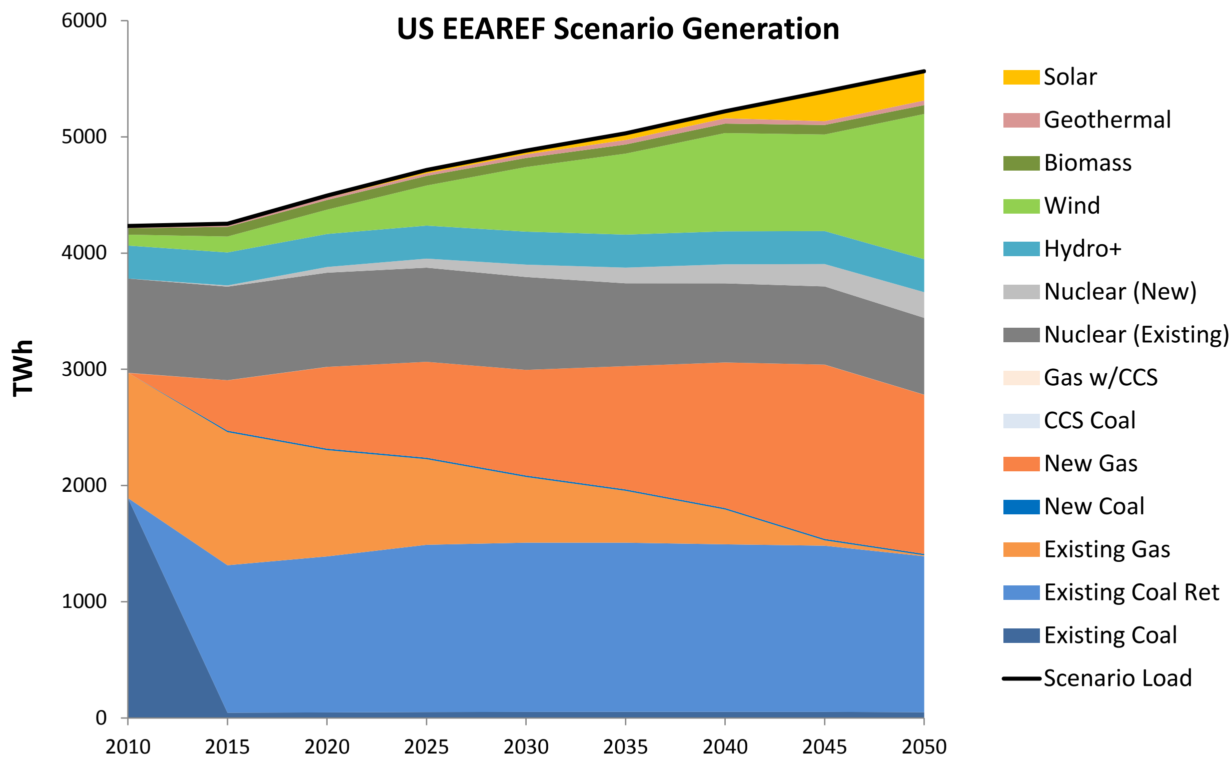

Figure 2-1
U.S. Generation Mix in the Reference Case[4]

The attractiveness of natural gas-fueled technologies has increased in the recent past.[5,6] Natural gas fired power plants typically have shorter licensing and construction times relative to coal, nuclear, and hydroelectric plants as well as lower capital cost to construct them.

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[4] Derived from *2014 REGEN Scenarios Analysis: Understanding Key Factors That May Impact Future Electricity Generation*. EPRI, Palo Alto, CA: 2014. 3002004880. p. 4-1.

[5] Op. cit., American Oil and Gas Reporter, May 2013.

[6] Natural Gas Dethrones King Coal As Power Companies Look To Future, National Public Radio, March 1, 2013. Available online at: http://www.npr.org/2013/03/01/173258342/natural-gas-dethrones-king-coal-as-power-companies-look-to-future . Accessed on February 27, 2015.

Fuel Diversity

In addition to concerns about "*generation diversity*," there also is concern about a very similar issue referred to as "*fuel diversity*." If companies and regions have a strong reliance on only one or two fuels for power generation, this situation can lead to large swings in electric prices if the dominant fuel exhibits large price volatility.

Depending on the region of the country, coal, nuclear and more recently natural gas generation are baseload power generation fuels used in the U.S., and both coal and uranium fuels are relatively low in cost and exhibit comparatively low price volatility. Wind and solar resources typically have no fuel cost, which automatically implies low fuel price volatility. Typically, natural gas not only costs more to generate a MWh of output than doing so with wind or solar, but natural gas prices have been highly volatile throughout recent history as a fuel for power generation, as shown in Figure 2-2.

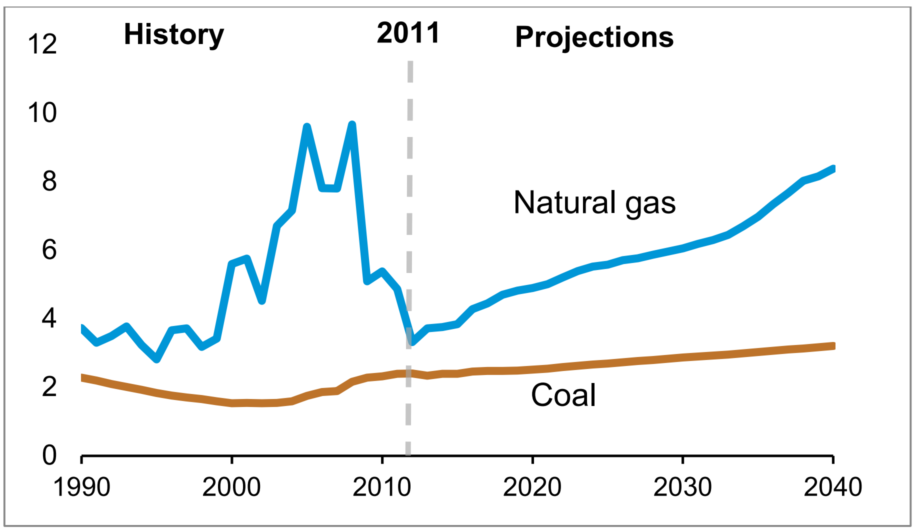

Figure 2-2
Energy Prices to the Electric Power Sector

(Source: EIA Annual Energy Outlook, 2013.)

Regions which are more heavily reliant on natural gas based power generation, such as California, the Northeast, and Texas, have experienced unpopular swings in retail electricity prices over time. These price swings led to a desire to diversify fuel mixes to reduce the uncertainty of electricity prices for end use customers.

The 2005 Energy Policy Act (EPAct 2005) requires electric companies to make efforts to achieve fuel diversity. The EPAct 2005 amended section 111(d) of the Public Utility Regulatory Policies Act of 1978 by adding Standard 12, which states: "*Fuel Sources — Each electric utility shall develop a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.*[7]"

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[7] See Standard 12 of the act in Section 111 (d).

Characteristics of Natural Gas Power Generation

Natural gas power plant technology has evolved significantly over the last 50 years, and there now is less technological risk associated with building and operating natural gas fired power plants either for baseload purposes or for peak power generation.

Natural gas power plants typically produce electricity with fewer air pollution emissions as compared to coal-fired technology, a technology that has been the electricity industry's workhorse for decades. Natural gas power plants also typically emit less than one-half the amount of carbon dioxide (CO_2) per MWh of generation as compared to a typical coal-fired power plant. This is an important consideration given regulation of CO_2 emissions in the electric sector now in place as well as under development by the EPA, and the potential for CO_2-focused legislation to be debated again in the future.

The comparison of natural gas to nuclear or renewable generation on an environmental basis is more difficult to ascertain, with the verdict depending on a variety of assumptions related to their performance, and value judgments about the social cost of different emissions.

A final element related to the potential desirability of natural gas-based power generation is the price of the fuel. In the recent past – except for a period in the 1990s – natural gas has been a higher cost fuel than other fuels considered to meet new generation capacity, such as coal. There is of course an exception for the most prominent renewables, wind and solar, which have virtually zero fuel costs once the plants have been constructed. However, in recent years, the cost *disadvantage* of natural gas-fired generation, particularly as compared to coal-fired generation, has diminished. Natural gas prices have dropped significantly, at times making natural gas-fired electricity less expensive (on a variable costs basis) than coal. More importantly, some market forecasters project natural gas prices could remain historically low, and relatively low compared to coal, now and perhaps for the next several decades.

Figure 2-3 shows three different potential trajectories of future natural gas prices developed by the U.S. Energy Information Agency (EIA). Low price projections are based on the recent success of new natural gas and oil production techniques commonly referred to as "fracking." Fracking reaches vastly more natural gas deposits and extracts the gas (at least in the U.S.) at lower cost than in most conventional natural gas wells. This new production method also may reduce the importance of some of the factors that have caused very high price volatility of natural gas in the past, such as hurricanes in the Gulf of Mexico. Lower prices for natural gas lead to more intermediate and even base load operation.

Renewable generation plants have similar, and in some cases even shorter development lead times compared to natural gas plants. However, they typically cost more on a capacity basis (i.e., dollars per kilowatt) than natural gas power plants. The ongoing reduction in cost for renewable technologies may reduce the cost advantage of natural gas plants over time.

Natural gas fired power generators also have an important operational advantage over the renewable power technologies, like wind and solar, that currently make up a large fraction of the new electricity capacity being added. Wind and solar plants exhibit are intermittent generation resources that cannot be dispatched. In addition their production is relatively unpredictable over the day and the year. There are many times during the year, or even during a given month, when renewables produce little or no output compared to their capacity. Natural gas generators are agile, meaning they can help smooth out fluctuations in renewables output across the day.

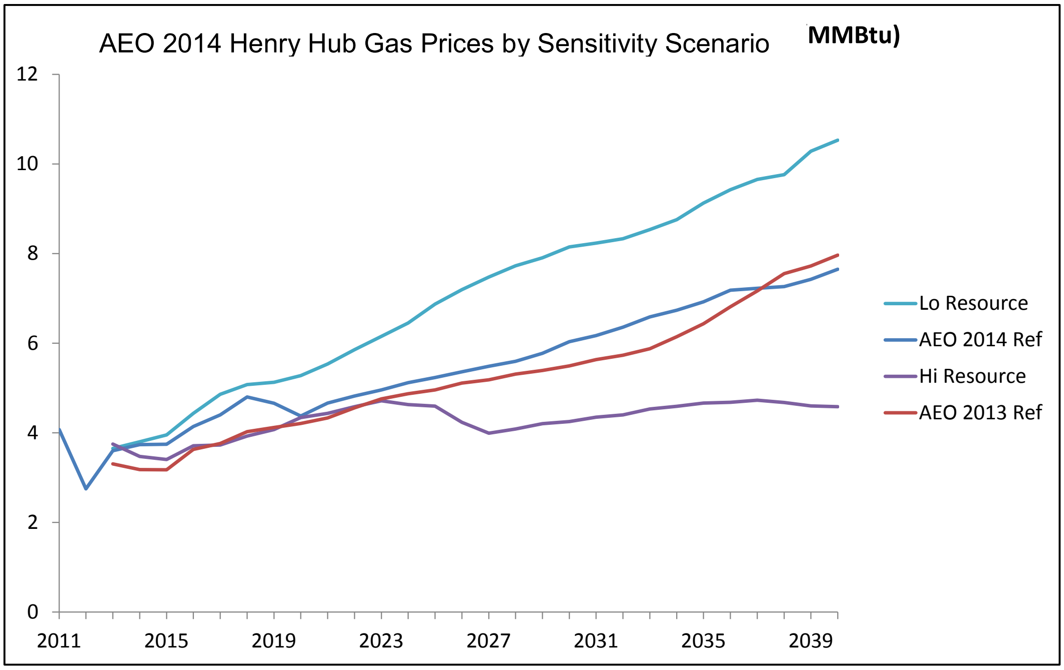

Figure 2-3
Natural Gas Price Trajectories (real $2012 per million Btu)

(Source: EIA, Annual Energy Outlook 2014)

Finally the very short-term fluctuations in renewable output can be rapid and occur at undesirable times. This situation is illustrated in Figure 2-4. As shown, on the morning of August 12, 2007, the wind resource in the Northwest Central region of the U.S. plummeted to near zero, while electric load was growing towards the day's peak. Conversely, during the evening load ramped down while wind capacity peaked. The agility of natural gas generation can help maintain the balance between supply and demand, a necessary condition for the stability of the electric grid.

During other times, renewable resources may generate more energy than is needed to meet load leading to negative marginal costs of power, as has been observed during the night time hours in west Texas. A power system that relies extensively on wind and solar resources will benefit from generators with the fast response of natural gas fueled units to meet customer demands in today's world.

However, if it is possible to develop large-scale, cost effective electricity storage technologies, it may be possible to rely more heavily on renewable resources. To date, efforts to develop storage technologies beyond pump-lift hydropower reservoirs have not yet achieved large-scale deployment.

Some companies and regions are attempting to address the problem of intermittent renewables generation by increasing the geographical diversity of their renewable resources, particularly wind. This approach may allow intermittency in one portion of the region to be smoothed by greater generation of renewables in another part of the region. Mixing wind resources with solar resources also may smooth the intermittency attributable to each renewables resource operated in isolation. Wind power also can cause problems achieving the stable frequency and voltage required to balance electricity supply and demand and ensure the quality of electric service expected in today's world. Natural gas fired capacity is particularly agile compared to coal and nuclear technologies, and can be ramped up or down quickly in response to changing electric loads.

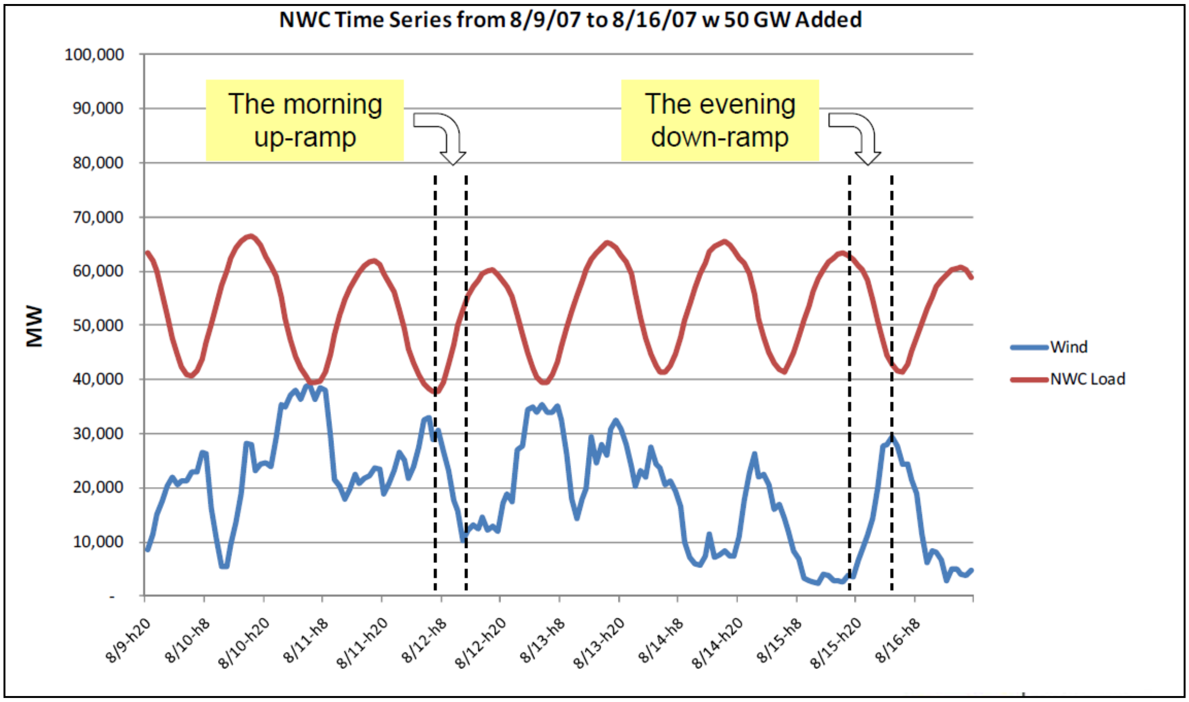

Figure 2-4
Periods of Anti-correlation of Wind and Electric Load[8]

The intermittency situation described above potentially could be addressed in different ways in the future which could alter the mix of generation technologies that electric companies might consider in terms of capacity additions. However, most current projections show a growing near-term reliance on natural gas fired power generation and renewables as the pillars of future capacity additions.

The expected domination of natural gas and renewable resources in terms of added capacity is due in part to the regulatory support provided to renewables, through such mechanisms as the Production Tax Credit (PTC), Investment Tax Credit (ITC), and mandatory state Renewable Portfolio Standards (RPS) that require a certain percentage of electricity consumed in a state to be composed of qualifying renewable resources.

[8] Presentation by Vic Niemeyer, "Implications of Integrating Wind at Scales that Matter for Climate Policy," CTOTF Workshop on Integrating Renewables into the Generation Mix, September 13, 2010.

Natural gas capacity also is expected to grow rapidly in the next decade or more due to its comparatively low capital and operating costs, relatively easy permitting, and reduced environmental "footprint" as compared to other resources.

3
LEVELIZED COST OF ELECTRICITY (LCOE)

The first part of our analysis involved analyzing how different types of new generation capacity may impact the *levelized cost of electricity (LCOE)* associated with potential development of a single new power generation asset. This part of our analysis highlights the economic decision making associated with a commitment to build a single new power plant on a stand-alone basis.

The LCOE represents an annualized cost of generating electricity over the lifetime of the unit, including initial capital, return on investment, and costs of operation, fuel and maintenance.[9] LCOE calculations combine the capital and O&M costs with the expected performance and operating characteristics of the plant into a cost per megawatt-hour basis. This procedure allows for comparison of technologies across a variety of sizes and operating conditions and allows for the comparison of the cost of electricity of a new plant with that of an existing plant. LCOE calculations are based on assumptions regarding future unit operations, operating costs, fuel prices, financing terms, and inflation. Figure 3-1 shows a representative LCOE graph for an NGCC unit while Figure 3-2 shows a representative LCOE graph for a nuclear plant. In the former, the fuel is the chief cost component, whereas in the latter, the upfront capital costs comprise a majority of the LCOE.

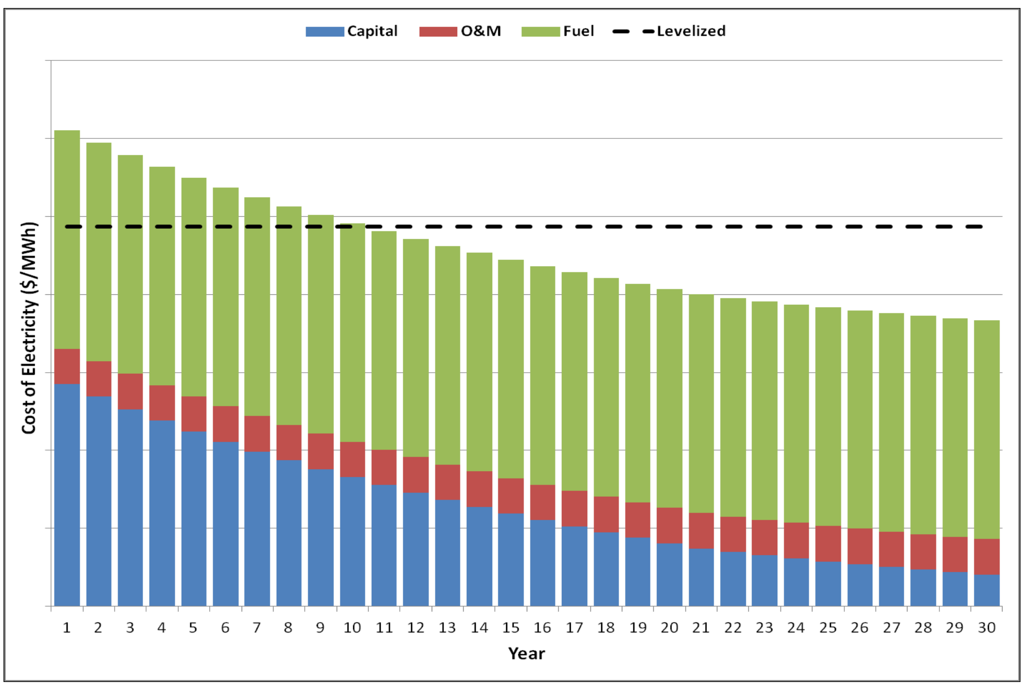

Figure 3-1
Example LCOE for Natural Gas Combined Cycle (for illustrative purposes only)

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[9] Much of the discussion in this section of the report is taken from *Program on Technology Innovation: Integrated Generation Technology Options 2012*. EPRI, Palo Alto, CA: 2013. 1026656, p. 1-6 and 1-7.

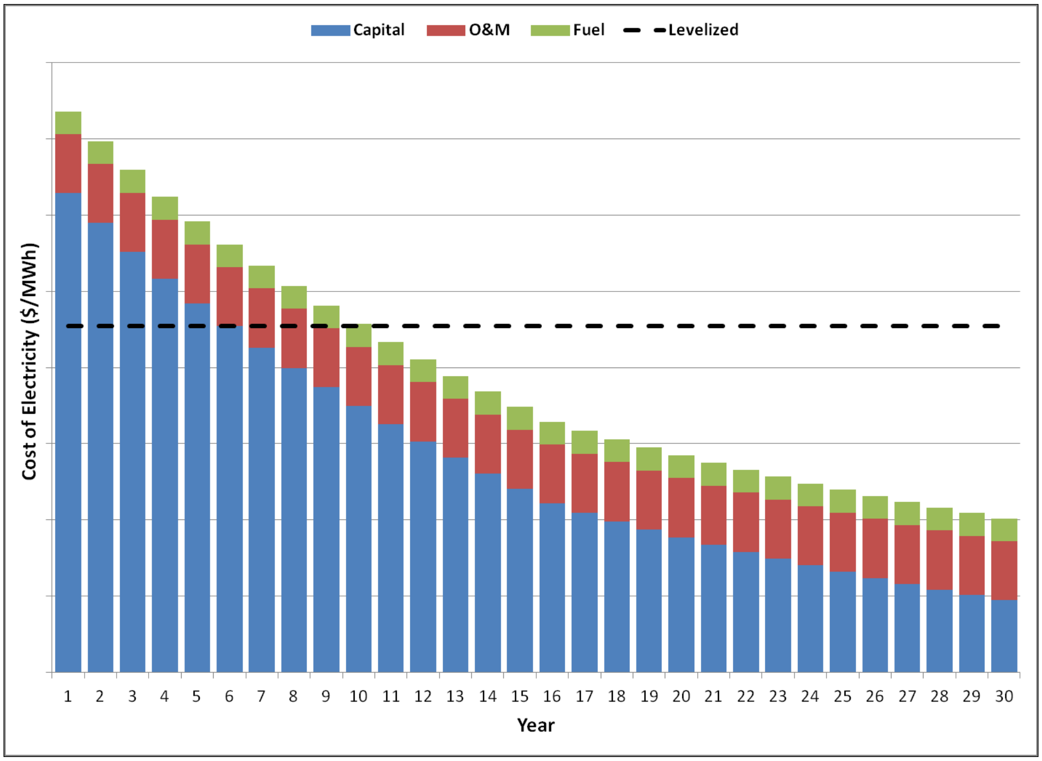

Figure 3-2
Example LCOE for Nuclear (for illustrative purposes only)

While LCOE is a convenient way of comparing generation technologies on a common basis and is used throughout the electric utility industry as a high-level screening tool, actual plant investment decisions are affected by a number of other project specific considerations. These may include the ability of the plant to generate electricity during periods when energy requirements are highest, the capacity value of the plant, environmental costs and benefits that certain technologies provide, the existing regional resource mix and desire for portfolio diversification, or costs associated with integrating intermittent resources into a system, such as additional operating reserves. Additionally, the variability and uncertainty of the inputs used in LCOE calculations, such as fuel, capital, and operating costs and capacity factors, can affect the results of LCOE comparisons among technologies.

Resource planners use a suite of planning tools to compare the range of attributes of new generation technologies for meeting new generation demands. While LCOE provides one way to compare generation technologies, it will not be the only factor considered in plant specific decisions, and caution should be used when comparing technologies based on LCOE.

Cost and Performance Data for Electric Generation Technologies

The cost and performance parameters used in our analysis are taken directly from the 2012 EPRI *Integrated Technology Options Report,*[10] and are shown in Table 3-1. We used 2014 real dollars

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[10] See *Program on Technology Innovation: Integrated Generation Technology Options 2012*. EPRI, Palo Alto, CA: 2013. 1026656. This report is available free of charge to the public here: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001026656 .

in this analysis, which are based on 2010 dollars inflated at 1.8% to 2014. All results are shown in levelized 2014 dollars over a thirty year lifetime.

Table 3-1
Cost and Performance of Candidate Technologies

		Generation Technology			
Variable	**Units**	**NGCC**	**Coal**	**Nuclear**	**Wind**
Fixed Charge Rate	Fraction of ONCC[1]	0.1	0.105	0.11	0.105
ONCC[1]	($/kW)	1175	2300	4450	2575
FOM[2]	($/kW-year)	17.00	51.20	117.20	37.20
VOM[3]	($/MWh)	2.40	2.10	1.80	15.10
Equivalent Availability[4]	(Fraction of hours)	0.95	0.89	0.91	0.40
Heat Rate	(MMBtu / KWh)	6,800	8,750	10,000	0
CO_2 Emissions	(metric ton / MWh)	0.36	0.84	0	0

Notes: 1. Overnight capital cost (ONCC).
2. Fixed operations and maintenance costs (FOM).
3. Variable operations and maintenance costs (VOM).
4. Equivalent availability represents the fraction of time that a technology is available to generate after subtracting both planned (maintenance) and forced outages for dispatchable technologies. For the wind technology, it is the fraction of the year that wind resources generate electricity.

Table 3-2 shows commodity prices used in our LCOE analysis for the Base case. It is important to note that these prices are shown on a levelized basis over a 30-year time horizon.

Table 3-2
Commodity Price Modeling Assumptions

Fuels	**Prices ($/MMBtu; levelized over 30 Years)**
Natural Gas (EIA 2014 Reference)	$5.50
Coal	$2.75
Nuclear	$0.40
CO_2 ($/tonne)	$10.00

Table 3-3 shows the quantitative results from our LCOE analysis. As shown, based on the assumptions described above, a new NGCC generating unit would be able to generate electricity for $59.56 per MWh, the lowest LCOE among the generation technologies evaluated here.

Table 3-3
Base Case Results (LCOE - $2014/MWh)

	NGCC	Coal	Nuclear	Wind
Fixed Cost (Levelized)	$14.12	$30.98	$61.41	$77.16
O&M (Fixed + Variable)	$4.44	$8.67	$16.50	$25.72
Fuel Cost	$37.40	$24.06	$4.00	$0.00
CO_2	$3.60	$8.40	$0.00	$0.00
Total LCOE	$59.56	$72.11	$81.91	$102.88

Sensitivity Analyses

While new NGCCs appear to be the generation technology that can generate electricity at the lowest levelized cost under the Base case conditions, it is important to consider the relative economics if some of the underlying assumptions differ from those we used in our Base case analysis. Below we discuss our sensitivity analysis results associated with different input fuel prices, different CO_2 emissions costs, different assumed capital costs and capacity factors.

Sensitivity results for different fuel prices

One key uncertainty in the future production cost of electricity is the cost of the fuel. We conducted sensitivity analysis using the different fuel prices shown in Table 3-4. As shown, using the alternative levelized fuel price of $8.80/MMBtu for natural gas, the lowest cost of energy would be provided by a new coal asset at $72.11 per MWh. Under these same alternate conditions, adding nuclear capacity also becomes more competitive relative to natural gas. If, on the other hand, the price of coal fell from $2.75 in the Base case to $1.50/MMBtu in an Alternate case, once again a new NGCC can be expected to provide the lowest cost of electricity among the technologies analyzed at $59.56 per MWh.

Table 3-4
Sensitivity Results for Different Fuel Prices (LCOE - $2014/MWh)

	Fuel Prices (Levelized $ per MMBtu)					
	Base	Alternate	CC	Coal	Nuclear	Wind
Base case			**$59.56**	$72.11	$81.91	$102.88
Gas	$5.50	**$8.80**	$82.00	**$72.11**	$81.91	$102.88
Coal	$2.75	**$1.50**	**$59.56**	$61.17	$81.91	$102.88

Sensitivity results for different levelized CO_2 emissions costs

One key uncertainty related to the future production cost of electricity is whether or not electric generators will be required to reduce their CO_2 emissions in the future under mandatory state or federal laws or regulations.

For the purposes of this analysis, we assumed electric generators in the future may have to obtain CO_2 emissions allowances as part of a CO_2 emissions cap and trade program like those that exists today in California and the nine northeastern states that participate in the Regional Greenhouse Gas Initiative (RGGI) program, or alternatively, may be required to pay an equivalent CO_2 emissions tax. For the purposes of this analysis, we assumed different CO_2 allowance prices or equivalent CO_2 emission taxes as shown in Table 3-5. We conducted sensitivity analysis as part of our LCOE analysis based on a \$0, \$10 and \$40 per ton CO_2 emissions price (real \$2014).

It is important to note that in June 2014 the US EPA released proposed guidelines that would require states to regulate greenhouse gas (GHG) emissions from *existing* electric generation units under section 111(**d**) of the Clean Air Act and *new* and *modified* power plants under section 111(**b**). None of these proposed rules establish either a national GHG cap-and-trade program or impose a CO_2 emissions tax designed to reduce future CO_2 emissions from power plants. Rather, the 111(b) proposal for new generation sources would impose a performance standard which all new generation sources would be required to achieve. The 111(d) proposal relies on individual states to develop 111(d) compliance plans that would achieve the statewide CO_2 emissions targets proposed by EPA. The proposed 111(d) rule would allow states such as California and multi-state regions like RGGI to develop compliance plans that could include market-based approaches like emissions trading and/or emissions taxes.

As shown in Table 3-5, regardless of the three levels of CO_2 emissions prices used in our simple LCOE analysis, the NGCC generation appears to offer the lowest LCOE based on the analytic assumptions used in our simplified analysis.

Table 3-5
Sensitivity Results for Different CO_2 Emission Prices (LCOE – real \$2014/MWh)

	CO_2 Prices (\$/tCO_2)	NGCC	Coal	Nuclear	Wind
Base	10.00	**\$59.56**	\$72.11	\$81.91	\$102.88
Low	0	**\$55.96**	\$63.71	\$81.91	\$102.88
High	40.00	**\$70.36**	\$97.31	\$81.91	\$102.88

Sensitivity results for lower capital costs

Another key uncertainty related to the future production cost of electricity is the future "overnight" capital cost to develop new power plants. For the purposes of this sensitivity analysis, we assumed capital costs for each generation technology based on EPRI's 2012 "Integrated Generation Options" report described above, and a lower capital cost scenario in which we assumed the capital costs are 25% lower than in the Base case.

As shown in Table 3-6, new NGCCs can be expected to provide the lowest levelized cost of electricity based on our analysis assumptions for both the Base case and an alternative case in which capital costs for all the evaluated technologies are assumed to be 25% below the costs used in the Base case analysis.

Of course, a sensitivity which lowers all of the technology costs by the same 25% may not be as interesting since one would expect the relative results to be similar to the Base case. In the future, EPRI may explore an alternative scenario that would evaluate the impact of just reducing nuclear costs by 30% to see how close one would get to the NGCC.

Table 3-6
Sensitivity Results for Different Capital Costs (LCOE - $2014/MWh)

Capital Cost	NGCC	Coal	Nuclear	Wind
Base Case	$59.56	$72.11	$81.91	$102.88
25% Lower	$56.03	$64.36	$66.56	$83.59

Sensitivity results for lower capacity factors

Another uncertainty related to the future production electricity is the appropriate capacity factor, or annual equivalent availability, to be used for each technology. Table 3-7 shows the different capacity factor assumptions we used in our sensitivity analysis of capacity factors.

Table 3-7
Capacity Factor Values used for Sensitivity Analysis

Capital Cost	NGCC	Coal	Nuclear	Wind
Base	95%	89%	91%	40%
Low Cap Factor	60%	60%	80%	40%

Table 3-8 shows our LCOE results based on the different capacity factors shown in Table 3-7. As shown, based on the analysis assumptions used in this simple analysis, it appears once again that new NGCCs can be expected to provide the lowest LCOE in both the Base case and the alternative case in which we applied lower capacity factors for NGCC, coal and nuclear generators.

Table 3-8
Sensitivity Results for Different Capital Costs (LCOE - $2014/MWh)

Capital Cost	NGCC	Coal	Nuclear	Wind
Base	$59.56	$72.11	$81.91	$102.88
Low Capacity Factor	$74.11	$101.39	$98.14	$102.88

Production tax credits for wind and nuclear generation

We also evaluated the extent to which a federal or state production tax credit (PTC) qualifying wind and nuclear generation might impact the LCOE from the four candidate technologies we analyzed. For the purposes of our analysis, we assumed the PTC was fixed at $23/MWh for 10 years.

As shown in Table 3-9, the inclusion of a 10 year PTC for wind and nuclear generation does not change the selection of the NGCC technology on the basis of the lowest levelized cost based on the analysis assumptions included here.

Table 3-9
LCOE Estimates for Generation Technologies with PTC ($23/MWh)

PTC Case	NGCC	Coal	Nuclear	Wind
Fixed	$14.12	$30.98	$49.86	$65.61
O&M	$4.44	$8.67	$16.50	$25.72
Fuel	$37.40	$24.06	$4.00	$0.00
CO_2	$3.60	$8.40	$0.00	$0.00
Total	$59.56	$72.11	$70.36	$91.33

Scenario Analysis of Electric Industry Futures

In addition to the sensitivity analyses described above, we also developed a set of future electric sector scenarios that were designed to be favorable for each of the potential generation technologies included in our LCOE analysis. The purpose of this analysis was to determine what kind of future scenarios might favor the future development of each of the generation technologies evaluated. In this case, we gain used the LCOE as the key metric to judge the “best” technology for each scenario.

A scenario that advantages new natural gas generation

The following characteristics provided the foundation for a future scenario that advantages development of new natural gas-fired generation capacity:

- Capital Cost increased by 20% for <u>all</u> technologies;
- Natural gas prices declines from $5.50 to $4.00 per MMBtu on a levelized basis; and,
- CO_2 emissions prices is set to $50/tCO_2$.

The primary rationale for this scenario would be increased U.S. natural gas production which would allow for taking advantage of our abundant resource base combined with continued improvements in natural gas hydraulic fracturing technology.

Table 3-10 shows the results of our LCOE analysis based on this scenario. As shown, the new natural gas-fired generation would offer the lowest LCOE compared to the other technologies analyzed here.

Table 3-10
Results from the Natural Gas Advantaged Scenario

Coal Case	NGCC (LCOE $)	Coal (LCOE $)	Nuclear (LCOE $)	Wind (LCOE $)
Fixed Cost	$16.94	$37.18	$73.57	$92.59
O&M	$4.44	$8.67	$16.50	$25.72
Fuel	$27.20	$24.06	$4.00	$0.00
CO_2	$18.00	$42.00	$0.00	$0.00
Total	$66.58	$111.81	$94.19	$118.31

Scenario that advantages new coal generation

The following characteristics provided the foundation for a future scenario that advantages development of new coal-fired generation capacity:

- Capital Cost reduced by 20% for all technologies;
- Coal price is reduced from $2.75 to $2.00 per MMBtu on a levelized basis;
- Natural gas price increases from $5.50 to $6.50 per MMBtu on a levelized basis; and,
- CO_2 emissions prices is set to zero.

The rationale for this scenario could be: (i) the cost of capital is at current (2014) historically low levels; (ii) reduced coal use in recent times decreases fuel prices; (iii) the use of natural gas hydraulic fracking technology declines due to drop in world oil price or environmental challenges, and as a result natural gas prices are higher than expectations.

Table 3-11 shows the results of our LCOE analysis based on this scenario. As shown, based on this scenario, the proposed coal-fired generation unit would offer the lowest cost of electricity as compared to the other technologies analyzed here.

Table 3-11
Results from the Coal Advantaged Scenario

Coal Case	NGCC (LCOE $)	Coal (LCOE $)	Nuclear (LCOE $)	Wind (LCOE $)
Fixed Cost	$11.30	$24.78	$49.13	$61.73
O&M	$4.44	$8.67	$16.50	$25.72
Fuel	$44.20	$17.50	$4.00	$0.00
CO_2	$0.00	$0.00	$0.00	$0.00
Total	$59.59	$50.95	$69.63	$87.45

A scenario that advantages new nuclear generation

The following characteristics provided the foundation for a future scenario that advantages development of new nuclear generation capacity:

- Nuclear capital and O&M costs reduced 20%;
- Natural gas price increase from $5.50 to $6.50 per MMBtu on a levelized basis; and,
- CO_2 emissions price is equal to $50 per ton on a levelized basis.

The rational for this scenarios could be as follows: (i) nuclear capital cost drops due to industry revitalization perhaps due to development of modular nuclear units; (ii) nuclear O&M costs fall reflecting longer life components; and (iii) stringent CO_2 mitigation policies are adopted that result in a high cost to emit CO_2.

Table 3-12 shows the results of our LCOE analysis based on this scenario. As shown, the proposed nuclear generation would offer the lowest LCOE compared to the other technologies analyzed.

Table 3-12
Results from the Nuclear Advantaged Scenario

Nuclear Case	NGCC (LCOE $)	Coal (LCOE $)	Nuclear (LCOE $)	Wind (LCOE $)
Fixed	$14.12	$30.98	$49.13	$7
O&M	$4.44	$8.67	$16.50	$25.72
Fuel	$40.20	$24.06	$4.00	$0.00
CO_2	$18.00	$42.00	$0.00	$0.00
Total	$80.76	$105.71	$66.33	$102.88

A scenario that advantages new wind generation

The following characteristics provided the foundation for a future scenario that advantages development of new wind generation capacity:

- Capital cost reduced by 20% for all technologies and an additional 20% for wind;
- Natural gas price increases from $5.50 to $6.50 per MMBtu on a levelized basis; and,
- CO_2 emissions price is equal to $50 per ton on a levelized basis.

The rational for this scenarios could be: (i) additional wind cost reduction due to continued learning and possibly due to higher hub heights; and, (ii) stringent CO_2 mitigation policies are adopted that result in a high cost to emit CO_2.

Table 3-13 shows the results of our LCOE analysis based on this scenario. As shown, the proposed wind generation would offer the lowest LCOE compared to the other technologies analyzed.

Table 3-13
Results from the Wind Advantaged Scenario

Nuclear Case	NGCC (LCOE $)	Coal (LCOE $)	Nuclear (LCOE $)	Wind (LCOE $)
Fixed	$11.30	$24.78	$49.13	$61.73
O&M	$4.44	$8.67	$16.50	$25.72
Fuel	$44.20	$24.06	$4.00	$0.00
CO_2	$18.00	$42.00	$0.00	$0.00
Total	$80.76	$99.91	$69.63	$67.73

LCOE Analysis Observations

The analysis we conducted for the first part of this project estimated the expected change in the LCOE for different possible new electric generation capacity expansion options resulting from different expectations of future CO_2 prices, input fuel prices, overnight capital costs for different types of electricity generation, production tax credits, and, capacity factors.

Based on our analysis, it appears that the lowest cost option from an LCOE perspective is the NGCC technology in several scenarios, except when natural gas prices or costs to emit CO_2 are much higher than assumed in the Base case. In the specific case of higher natural gas prices only, new coal generation would offer the lowest levelized cost of electricity.

However, it is important to recognize the new coal plant specified in this analysis would not be allowed to be built if EPA finalizes its recently proposed 111(b) regulation for CO_2 emission from new fossil-fired generation sources. The coal technology in the analysis would require a relaxed limit on CO_2 emissions from a new coal plant or a price-based regulation on CO_2 emissions that resulted in low CO_2 prices. Based on the analysis shown here, in the event that natural gas prices were expected to follow the higher alternate scenario of $8.80 per MMBtu, than the lowest cost of energy would be provided by the new nuclear plant described here, as the new coal plan would not comply with the proposed section 111(b) regulation.

While new NGCC technology is favored from an LCOE perspective based on the technology and performance assumptions and commodity prices included in our Base case analysis, it is possible to imagine scenarios that reveal advantages of each of the potential new generation technologies evaluated here, including NGCCs, coal, wind and nuclear generation.

Unquantified Issues

In addition to the LCOE, electric companies, state regulators and other stakeholders may be interested in understanding how different proposed new generation technologies might impact a broader array of issues of concern. Table 3-14 below identifies specific issues related to electric sector capacity expansion that are not quantified in our analysis, but may be very important when electric companies, state PUC's and others consider new generation options. Also, in Table 3-14, we have tried to provide some qualitative estimates of how these issues might impact the attractiveness of the new generation options evaluated here.

Table 3-14
Unquantified Issues to be Considered

Issue	Qualitative Impact on Attractiveness of New Generation			
	NGCC	Coal	Nuclear	Wind
Fuel supply interruption	—	+ / —	+	+
Tighter environmental regulations	+	—	?	
Fuel price volatility	—	+	+	+
Investment size	+	—	—	+
Technology learning			+	

Fuel supply interruption

This refers to the potential for fuel supplies to be physically disrupted, for example, by a problem with the railroad or barge transportation infrastructure that delivers coal or natural gas pipeline disruptions or capacity constraints.

Tighter environmental regulations

Over the next decade, many observers expect the federal government and state agencies to impose a range of tighter environmental regulations that will have a strong influence on the types of electric power generation technologies and fuels that are used to generate electricity. The analysis conducted here does not directly address whether the power generation technologies described here will continue to comply with more stringent future environmental regulations.

Fuel price volatility

Fuel prices, particularly natural gas, are notoriously volatile. Our analysis includes different natural gas price assumption to assess the impact of change in expected long-range natural gas prices, but our analysis does not explicitly address the challenges of short-term natural gas price volatility, and how companies gain physical access to needed fuels during times of shortage.

Investment size

Another important consideration when developing new generation is the size of the required investment. Our analysis assumes a “project developer” can access needed investment funds, which may not be true in the real world. Our analysis here does not directly address a company’s credit worthiness or capability to obtain the capital needed to make the investments analyzed in this report. In the real world, companies need to consider how difficult it may be to get financing to construct a proposed new generation unit based on a newer “more risky” or capital-intensive technology than a technology like NGCC that is well known and not subject to unforeseen operating risks.

Technology learning

Companies also may be interested in investing in certain types of generation facilities to learn how to build and operate a new technology. While this type of innovative power generation facility may not be the most cost-effective to construct from an economic optimization perspective, it may make sense for a company to build this type of plant if doing so can provide the company with a long-term improvement in its operations or a strategic knowledge advantage in terms of its competitors.

4
PORTFOLIO ANALYSIS OF INCREMENTAL GENERATION ADDITIONS

The next step in our analysis was to optimize the addition of new generation capacity to an *existing portfolio* of generation assets, and track the profitability and the risk of the assets as they participate in a regional power market.

For this analysis EPRI evaluated what changes in the underlying economic and regulatory assumptions might alter a decision to build new natural gas-fired generation and instead invest in other generation technologies. Key variables evaluated included: (i) changes in expected future natural gas prices: (ii) potential regulatory changes that may require significant electric sector carbon emissions reductions; and (iii) potential changes in the cost and performance of key underlying generation technologies.

Our goal here was to explore adding incremental capacity to different existing generation portfolios, and analyze the changes in resulting levelized annual cash flows for a typical year for each generation portfolio. For each portfolio, we tracked portfolio value using the *mean* and *standard deviation* of annual cash flows, and the likelihood of negative cash flow. The cash flow consists of the cash flow from selling electricity, property tax and insurance (PTI), and the cost of servicing debt. Later in the analysis, we will "close the loop" by adding in the "cost" of equity financing for the capacity addition into the overall economic valuation.

To accomplish this analysis, we ported the data from the LCOE analysis described in section three to the portfolio analysis. Subsequently, this data was enriched to include uncertainty in the key determinants of the rewards and risks of generation portfolios. Recall, that in our analysis "reward" is calculated as a change in expected mean levelized cash flows; and "risk" is calculated as a change in the standard deviation of the expected reward.

"Open Loop" Financial Analysis

The "open loop" analysis described below assumes an existing portfolio of electric power generation assets has both positive and negative annual cash flows associated with it. On the positive side, an electric company can expect to receive revenues for each MWh of electricity it generates and sells into the regional power market. On the negative side, an electric company can expect to bear annual expenses associated with operating its power plants including fuel purchases (e.g., natural gas, coal), labor costs, fixed and variable operations and maintenance expenses (FOM and VOM), property taxes and insurance (PTI). Importantly, the open loop analysis also includes the obligated annual financial cost to service any debt obligations the company may have incurred associated with the construction of the power plants contained in the portfolio.

In the open loop analysis of cash flows described below, we have included all of the annual revenues and expenses mentioned above as part of the annual cash flows associated with each power plant included in the representative portfolios. Importantly, we also assume the annual expenses associated with serving the debt that would have been issued by the company for the portion of the overnight capital cost (ONCC) associated with each power plant included in each representative portfolio. For our analysis, we assumed in each case that 50% of the ONCC for each power generation technology was financed using debt instruments that incur a legal obligation upon the company to pay annual related interest payments, and 50% of the ONCC was financed using shareholder equity, which does not impose an annual cash flow obligation on the company.

The open loop analysis below is based on the cash flows associated with each of the three example asset portfolios, and is designed to evaluate how these cash flows can be expected to change with the addition of the "obligated" cash flows associated with acquisition or development of a new power generation asset. This type of open loop analysis is of interest to corporate financial strategists and Chief Financial Officers (CFOs) because it provides insight into the expected required changes to annual cash flow and associated financial risks that may result from the addition of new assets to a generation portfolio.

Table 4-1 shows the ONCC for key electric generation technologies analyzed in this report. The ONCC for a given electric technology is the expected total capital cost of building a new power plant, and assumes the plant effectively is built "overnight." This is a standard assumption used in financial analysis of proposed new power plants. There are four possible ONCC values shown for each generation technology to represent the potential uncertainty in this cost.

Table 4-1
Overnight Capital Cost of Key Technologies ($/kW)

Wind	NGCC	Nuclear	Coal
2,800	1,400	5,000	2,600
2,600	1,200	4,600	2,300
2,500	1,100	4,200	2,200
2,400	1,000	4,000	2,100

Table 4-2 shows the operating data we assumed for each of the power generation technologies included in the asset portfolios we analyzed.

Table 4-2
Operating Data by Electric Power Generation Technology

Variable	Wind	NGCC	Nuclear	Coal
Heat Rate (MMBtu/KWh)	0.40[1]	6,800	10,000	8,750
Variable O&M ($/MWh)	6.00	2.40	1.80	2.10
Fixed O&M ($/kW-yr)	12.00	17.00	117.20	51.20
CO_2 Emissions (tonnes/MWh)	--	0.36	--	0.84
Equivalent Availability (Fraction)	--	0.95	0.91	0.89
Notes: 1. Refers to the capacity factor of wind under "heat rate."				

The Regional Power Market

The regional power market simulation used for our analysis assumes each portfolio of generation assets serves a regional power market. The regional power market is defined by power prices for each of the 8,760 hours in a year. The price in each hour is set by the marginal variable (dispatch) cost of the marginal technology. There are three "states" of the power market in our simplified analysis (i.e., *tight, balanced and loose*) defined by the tightness of the supply and demand balance. These three power market conditions and the type of power generation on the "margin" in each case is shown in Table 4-3.

Table 4-3
Power Market Simulation

	Hours on the Margin per Year Market Balance					
Technology	**Tight**	**Balanced**	**Loose**	**Heat Rate (MMBtu/KWh)**	**VOM ($/MWh)**	**CO_2 (tCO_2/MWh)**
NatGas GT	2,760	1760	0	11,500	2.00	0.61
Old NGCC	4,000	2,000	760	9,500	3.00	0.48
Advanced NGCC	2,000	4,000	6,000	7,500	2.40	0.4
Old Coal	0	1,000	2,000	10,000	2.10	1.0
Total	8,760	8,760	8,760			

For example, as shown in Table 4-3, in the "tight" market, natural gas GTs are expected to be on the margin 2,760 hours per year, "old" NGCC for 4,000 hours per year, and advanced NGCCs for 2,000 hours per year. When NatGas GTs are on the margin, our simulation assumes the heat rate is 11,500 Btu/KWh, VOM is $2.00 per MWh and CO_2 emissions are 0.61 tons per MWh.

Commodity Prices for Portfolio Analysis

Table 4-4 shows the commodity prices used in our analysis. As shown, the CO_2 price is assumed to range from $10-$100 per ton while the natural gas price is assumed to range from a 30-year levelized value of $6.50 per MMBtu and a low of $4.50 per MMBtu. Please note these are assumed to be 30-year annual *levelized* real costs of fuel, and are <u>not</u> annual nominal or real fuel prices. These natural gas prices largely correspond to the range of natural gas prices used by EIA in the 2014 Annual Energy Outlook (AEO) for the Low Expected Ultimate Recovery case (LEUR) to the Higher Expected Ultimate Recovery case (HEUR).

In our analysis, we assume all scenarios for a given commodity (e.g., natural gas prices, power market conditions, etc…) have an <u>equal</u> likelihood of occurring, and all probabilities are assumed to be independent. For example, we assume there is a 33.33% probability the power market in any given year is either tight, balanced or loose, and the state of the power market year-to-year is independent of, for example, the natural gas price for the year.

It should be recognized that assigning these probabilities can be challenging to implement in practice depending on the specific nature of the scenario inputs. For example, it may be difficult in practice to assign a specific probability for a particular fuel price forecast, or to the final enactment of a specific environmental regulation or its stringency. History has proven that predicting the future environment in which electric companies may operate is extremely difficult, if not impossible. Admitting there are a wide range of possible future outcomes, and explicitly tracing the impacts that may result from the realizations of different potential future scenarios is both more realistic and insightful.

Because of these challenges, some parties may call into question the validity of this kind of probability analysis. It is important for "consumers" of this kind of analysis to clearly understand that arbitrary probability assignments for these types of inputs for scenarios can lead to misinterpretation of results, or too heavy reliance on specific results that may change if the underlying probabilities change. Because of the inherent difficulty associated with these types of probabilities, we assumed in our analysis that all scenarios for a given commodity (e.g., natural gas prices, power market conditions, etc…) have an <u>equal</u> likelihood of occurring.

Our analysis contains a rich tapestry of market prices. As shown in Table 4-4, there are six future scenarios associated with the generation fuels (i.e., three CO_2 prices x two natural gas prices). The three market scenarios imply different supply and demand balances the wholesale electricity market. By combining the fuel scenarios with the power market scenarios, we have created a total of 18 different possible price scenarios (i.e., 6 x 3 = 18).

Table 4-4
Commodity Prices

	CO_2 ($/tonne)	**Natural Gas** ($/MMBtu)	**Other Fuels** ($/MMBtu)	
High	100	6.50	Coal	2.75
Med	40	--	--	--
Low	10	4.50	Nuclear	0.40

This is designed to parallel the experience over the last several decades during which electric power markets have experienced wide swings in wholesale electricity prices and fuel prices. In total, there are a large number of composite future scenarios that were conducted as part of our analysis. The total number of future scenarios equals 576, or the product of 3 x 2 x 3 x 32. This is because there are three CO_2 price realizations, two different natural gas price levels, three representations of the power market, and 32 combinations of "new" technology capital costs (i.e., eight technologies with four potential capital costs for each).

As discussed above, each of the components of the large-scale scenarios has an equal probability (likelihood) of occurring. This allows the unbiased calculation of the likelihood of the composite scenario as the product of the individual event (i.e., natural gas price, CO_2 price, electric market condition, nuclear capital cost . . .) probabilities. This approach makes it possible to produce the statistical information to construct a probability density function like that shown in Figure 1-1.

Illustrative Power Generation Asset Portfolios

In conducting this simplified illustrative analysis, we evaluated the potential addition of incremental generation to three different example portfolios of existing generation assets: (i) a coal-dominated portfolio; (ii) a natural gas-dominated portfolio; and, (iii) a diverse portfolio characterized by a large portion of renewable resources and relatively "cleaner" burning fossil-fired power plants. We believe analysis of capacity expansion for each of these illustrative asset portfolios will help to illustrate the analytic methods we used which may prove helpful to electric companies considering new capacity additions, and provide insights into capacity expansion choices in today's world.

Table 4-5 describes the three example electricity portfolios we have used in our illustrative analysis (i.e., Coal, Gas, and Diverse) to evaluate different capacity expansion options for new generation that could be added to each portfolio either to increase its expected return (mean) or reduce its risk (standard deviation), or both.

Table 4-5
Generation Capacity for Each Candidate Portfolio (MW)

Portfolio	Electric Generation Technology (MW)					
	Coal	NGCC	NGGT	Nuclear	Wind	Total
Coal	8,000	1,500	0	500	0	10,000
Gas	0	8,000	1,500	0	500	10,000
Diverse	2,000	3,000	1,500	2,000	1,500	10,000

As shown in Table 4-5, we assumed the coal-dominated portfolio is comprised of 8,000 MW of existing coal-fired power plants, 1,500 MW of NGCC and 500 MW of nuclear generation. The Gas dominated portfolio consists of 8,000 MW of NGCC generation, 1,500 MWh of NGGT and 500 MW of wind. The Diverse portfolio is made up of 2,000 MW of coal, 3,000 MW of NGCC, 1,500 MW of NGGT, 2,000 MW of nuclear and 1,500 MW of wind.

Our analysis is designed to evaluate the expected performance of new generation capacity that may be added to each of three different illustrative electric generation portfolios.[11] The expected performance of each asset portfolio is determined by adding up the expected annual cash flows that would result from power generated by each technology contained in the portfolio. The expected cash flow for each the portfolio represents the levelized expected annual cash flow over 30 years during which we assume that fuel prices, the state of the regional power market and other variables change. In other words, these annual values are calculated for each of the multiple realizations (scenarios) that can be expected based on the variation defined for each underlying variable and then the average of all of these possible cash flows is computed. Using the likelihoods of the various scenarios enables us to calculate the mean, standard deviation, and the fraction of the time that the technology or portfolio results in a negative contribution to the levelized annual cash flows.

We urge readers to use caution when reviewing the results of our analyses shown in this report, and to avoid developing strong conclusions based on the illustrative, quantitative analysis described here. The assumptions used to conduct our analyses were selected to be a reasonable representation of that state of today's electric power business and the near-term future. However, these assumptions differ by region, and can quickly change over time, leading to very different results. The examples described here are **illustrative only**. We constructed them to inform readers about one way to study generation diversity, and to familiarize them with some of the kinds of insights these analytic methods can help to elucidate.

Adding new capacity to a coal-based generation portfolio

Table 4-6 illustrates the results of our "open loop" cash flow analysis evaluating the potential addition of new generation assets to the example Coal-based asset portfolio. As shown, the cash flows from the assets contained in the Coal portfolio have an expected levelized annual return of

[11] The analysis described here does not include subsidies for renewable power resources such as the Production Tax Credit (PTC) or Investment Tax Credit (ITC).

-$265 million based on the assumptions incorporated in our analysis and described above in sections three and four. This implies the Coal portfolio is expected to lose a substantial amount of money annually. This Coal portfolio has a standard deviation of $909 million per year which is a measure of financial risk. There is a 67% probability that the "true" value of the annual cash flows will fall within one standard deviation of the estimated financial return, and a 95% probability that the true value lies within two standard deviations of the expected value. The probability of negative cash flow in any single year for the Coal portfolio is 61 percent.

Table 4-6
Analysis of Incremental Generation – Coal Portfolio

Portfolio / Proposed New Generation	**Mean Levelized Financial Return** ($millions/year)	**Standard Deviation of Annual Financial Return** ($millions/year)	**Probability of Negative Cash Flow**
Coal	**-265**	**909**	**0.61**
+ 500 MW CC	**-228**	**899**	**0.60**
+ 500 MW Coal	-305	933	0.63
+ 500 MW Wind	-303	944	0.63
+ 500 MW Nuclear	**-218**	**883**	**0.60**
+ 1000 MW CC	**-192**	**890**	**0.59**
+ 1000 MW Nuclear	**-170**	**866**	**0.58**
+ 2500 MW CC	**-84**	**870**	**0.54**
+ 2500 MW Nuclear	**-29**	**871**	**0.51**

As shown in Table 4-6, we examined the potential addition of 500 MW of new NGCC, coal, wind and nuclear generation units to the base Coal portfolio. As shown, the addition of 500 MW of new NGCC generation would improve the expected annual levelized financial return of the Coal portfolio by reducing the expected negative cash flow from -$265 million to -228 million, an improvement of $37 million in levelized expected annual cash flow. In addition, the probability of negative annual cash flow is expected to fall slightly to 60 percent. Finally, the addition of the NGCC unit would reduce the standard deviation, or financial risk, of the Coal Portfolio slightly from $909 million to $899 million. In short, adding this new NGCC capacity can be expected to increase the financial performance of the Coal portfolio and slightly reduce the financial risk associated with it. The performance of this addition is a dominant solution in that it increases the expected financial return of the Coal portfolio, reduces the standard deviation and the probability of negative cash flow.

In comparison, the addition of 500 MW of new nuclear generation to the Coal portfolio can be expected to reduce the negative expected annual mean financial return from the Coal portfolio even more to -$218 million. This is an improvement over the Coal portfolio and the +500 MW NGCC addition, and the proposed new nuclear generation would reduce the standard deviation even more than the new NGCC to a level of $883 million. This implies that the new 500 MW nuclear addition would offer better financial performance than the addition of a new 500 MW NGCCs.

Also as shown, we evaluated the potential addition of 1000 MW of new NGCC or nuclear generation to the Coal portfolio. Either of these additions can be expected to increase the expected financial returns and reduce the financial risk of the portfolio. Of these, the 1,000 MW nuclear addition offers the greatest increase in expected financial return from -$265 million to -70 million and the largest reduction in standard deviation, or risk, from $909 million to $866 million. Finally, the addition of a 1,000 MW nuclear unit also would slightly reduce the probability of negative cash flows from 0.61 to 0.58.

Finally, we evaluated the potential addition of 2,500 MW of new NGCC or nuclear generation to the Coal portfolio. In this case, either of these large-scale additions would dramatically improve expected cash flows from $-265 million to -$84 million and -$29 million respective per year. In addition, the standard deviation (870 and 871 respectively) and the probability of negative cash flows (0.54 and 0.51 respectively) both fall with the addition of the cash flows associated with additional of 2,500 MW of new combined cycle or new nuclear capacity.

As described, above diversifying the Coal portfolio by adding new NGCCs or new nuclear units would increase the expected financial return from the Coal portfolio, and reduce the financial risk of the portfolio, and reduce the probability of experiencing negative cash flows. For all three size classes of additions analyzed here – 500 MW, 1,000 MW and 2,500 MW, it appears that the nuclear additions would improve the economic performance of the Coal portfolio more than the addition of new NGCCs of equal size. While the additional of new nuclear units offers the best opportunity of those new generation configurations evaluated here to improve the financial performance of the Coal portfolio, the addition of new nuclear units would require substantially more capital to be invested than building new NGCCs of the same size.

Adding new capacity to a natural gas-based generation portfolio

Table 4-7 illustrates the results of our open loop cash flow analysis evaluating the potential addition of new generation assets to an existing Gas dependent generation asset portfolio. As shown, the cash flows from the modeled Gas portfolio has an expected levelized annual return of $674 million based on the data and assumptions discussed above in sections three and four. As shown, the Gas portfolio can be expected to have a standard deviation of $639 million per year, and the probability of negative cash flow in any one year is 15 percent. Obviously, this asset portfolio is expected to perform a lot better financially than the Coal portfolio under the assumptions used here.

Table 4-7
Analysis of Incremental New Generation – Gas Portfolio

Portfolio / Proposed New Generation	**Mean Levelized Financial Return** ($millions/year)	**Standard Deviation of Annual Financial Return** ($millions/year)	**Probability of Negative Cash Flow**
Gas	**674**	**639**	**0.15**
+ 500 MW CC	**710**	648	**0.14**
+ 500 MW Coal	634	646	0.16
+ 500 MW Wind	636	651	0.16
+ 500 MW Nuclear	**722**	666	**0.14**
+ 1000 MW CC	**746**	656	**0.13**
+ 1000 MW Nuclear	**770**	691	**0.14**
+ 2500 MW CC	**926**	761	**0.12**
+ 2500 MW Nuclear	**914**	772	**0.12**

As shown in Table 4-7, we examined the addition of 500 MW of new NGCC, coal, wind or nuclear generation to the Gas portfolio. As shown, the addition of 500 MW of new nuclear generation would improve the expected annual levelized financial return of the Gas portfolio by increasing the expected annual cash flow to the largest extent, up to $722 million from $674 million. In addition, the probability of negative cash flow would fall slightly to 14 percent. While the selection of 500 MW of new nuclear generation would increase expected cash flow and reduce the probability of annual net negative cash flows, the addition of this new generation would *increase* slightly the standard deviation of the expected annual financial returns, indicating that the cash flow would be slightly more risky than in the Gas portfolio.

We also evaluated the potential addition of 1000 MW of new NGCC or nuclear generation to the as portfolio. Either of these additions will increase the expected financial returns and reduce the financial risk of the portfolio. Of these, the 1,000 MW nuclear addition offers the largest increase in expected financial return from $674 million to $770 million, and a slight reduction in risk from 0.15 to 0.14. However, the addition of either 1,000 MW NGCC or nuclear generation can be expected to increase the standard deviation, or risk, of the base Gas portfolio.

We also evaluated the potential addition of 2,500 MW of new NGCC or nuclear generation to the Gas portfolio as shown in Table 4-7. Both of these large-scale additions would improve expected cash flows from the Gas portfolio from $674 million to $926 million and $914 million respectively. However, as shown, both of these additions also would increase the standard deviation, or risk, associated with the cash flows in the Gas portfolio. Finally, both of these proposed generation additions can be expected to slightly reduce the risk of negative cash flows from 0.15 to 0.12.

The results shown in Table 4-7 demonstrate important interactions between expected cash flows, financial risk, and the probability of negative cash flows. In several of the cases shown, the proposed new generation additions (e.g., 500 MW nuclear, 1000 MW CC, 1000 MW nuclear) would increase the expected cash flows for the base Gas portfolio, but they would also increase the financial risk associated with the base Gas portfolio.

To be a truly "dominant" generation addition, a proposed new addition needs to offer improved cash flows, lower financial risk and lower probability of negative cash flows. As shown, none of the proposed additions shown in Table 4-7 are dominant over the Gas portfolio based on all three of these important metrics.

Adding new capacity to a diverse power generation portfolio

Table 4-8 illustrates the results of our open loop cash flow analysis evaluating the potential addition of new generation assets to the Diverse generation asset portfolio. As shown, the cash flows for the modeled Diverse portfolio has an expected levelized annual return of $770 million based on the assumptions incorporated in our analysis and described above in sections three and four. As shown, this Diverse generation portfolio can be expected to have a standard deviation of $687 million per year and a probability of negative cash flow in any single year of 0.13.

Table 4-8
Analysis of Incremental Generation – Diverse Portfolio

Portfolio / Proposed New Generation	Mean Levelized Financial Return ($millions/year)	Standard Deviation of Annual Financial Return ($millions/year)	Probability of Negative Cash Flow
Diverse	**770**	**687**	**0.13**
+ 500 MW CC	**806**	702	0.13
+ 500 MW Coal	729	689	0.15
+ 500 MW Wind	731	708	0.15
+ 500 MW Nuclear	**817**	737	0.13
+ 1000 MW CC	**842**	909	**0.12**
+ 1000 MW Nuclear	**864**	795	0.14
+ 2500 MW CC	**952**	718	**0.09**
+ 2500 MW Nuclear	**1,005**	975	0.15

As shown in Table 4-8, we examined the potential addition of 500 MW of new NGCC, coal, wind or nuclear generation to the Diverse portfolio. As shown, both the 500 MW new NGCC and nuclear generation would improve the expected annual levelized financial return of the Diverse portfolio by increasing the expected annual cash flow. However, both of these additions also would increase the financial risk associated with the Diverse portfolio because they would increase the standard deviation. In both cases, the risk of negative cash flow is identical to the Diverse portfolio (0.13). However, the addition of the new nuclear unit would increase the expected cash flow more than the proposed new NGCC.

Similar results are shown for the potential addition of 1,000 MW of new NGCC or nuclear generation to the Diverse portfolio. In both cases, the expected cash flow would increase for both of these new additions, but both also would increase the financial risk associated with the cash flows. In this case, the nuclear addition offers the larger increase in expected cash flow ($864 million), but the 1000 MW NGCC offers lower probability of negative cash flow (0.12).

We also evaluated the potential addition of 2,500 MW of new NGCC or nuclear generation to the Diverse portfolio as shown in Table 4-8. Both of these large-scale additions would improve expected cash flows from the Diverse portfolio, but both of these potential additions would increase the financial risk of the Diverse portfolio as they both would increase the standard deviation of the cash flows. Interestingly, the proposed 2,500 MW nuclear addition offers the largest potential increase in cash flows, but also would increase the financial risk more than the Diverse portfolio, and more than the addition of 2,500 MW of NGCC. However, as shown, the addition of 2,500 MW of NGCC can be expected to reduce the probability of negative cash flow for the Diverse portfolio, and as compared to the addition of 2,500 MW of new nuclear generation. As shown, neither of these additions are truly dominant as neither of these would improve cash flow, reduce risk and reduce the probability of negative cash flow as compared to the Diverse portfolio.

Open Loop Analysis Results

Based on the open loop analyses described above, it appears that the addition of new NGCCs or nuclear generation capacity could improve the expected annual levelized cash flows for the Coal, Gas and Diverse portfolios. Interestingly, neither the addition of new coal or wind generation to the existing three asset portfolios appears to offer improved financial performance.

Also, the results shown in Tables 4-6, 4-7 and 4-8 illustrate that proposed new generation additions may improve expected cash flow, but doing so may also increase expected financial risk and/or the probability of experiencing negative cash flows.

To be a truly "dominant" generation addition, a proposed new addition would need to offer the potential for improved expected cash flows, lower financial risk and lower probability of negative cash flows. As shown, a number of the proposed additions dominate the Coal portfolio (e.g., 500 MW nuclear, 500 MW NGCC), but none of the proposed additions are truly dominant in the cases of the Gas or Diverse asset portfolios. This is important to understand. For both of these portfolios, some of the new generation additions offer the potential to increase annual cash flows, but doing so also is expected to be accompanied by increased financial risks or a greater probability of experiencing negative cash flows.

Also, in addition to the financial metrics considered here, it is important to recognize that each of the proposed generation additions have other associated attributes that may make them more or less attractive for an electric company. For example, the addition of incremental nuclear generation would require an electric company to have access to substantially more capital than would be necessary to build a similarly sized NGCC unit, and many companies may not be able to access the capital needed to build new nuclear units. Other issues, such as obtaining air pollution control permits or permits to withdraw water for cooling, also may have a significant impact on future generation choices.

Importantly, the open loop analysis is *not* complete. From the perspective of a company considering an *investment decision*, the financial analysis related to capacity expansion needs to include not only the expected annual revenues and obligated expenses, but also needs to include the substantial shareholder equity the company would need to commit to build new generation.

"Closed Loop" Analysis of Generation Additions

In this section of the report, we describe the results of our "closed loop" analysis of potential new generation capacity additions. This analysis is based on the same positive cash flows (i.e., revenues) and negative cash flows (expenses) included in the open loop analysis described above. The critical difference between the "open" and "closed" loop cash flow analyses described here is that in the "closed loop" analysis, we also account for the 50% of the overnight capital costs of building new generation that we assume would be funded with shareholder equity rather than debt.

Because the "closed-loop" analysis includes all of the expected capital costs (i.e., equity and debt) required to build a new power plant, this kind of analysis is more akin to what is normally thought of as project "investment" analysis, and is designed to determine if the addition of new generation capacity can be expected to result in a positive or negative net present value for the associated investment.

The profit for an independent power producer (IPP) or the financial value created for rate payers in the case of an investor-owned utility (IOU) must reflect the equity capital invested for the IPP, or the revenue requirement on the equity investment for an IOU. The equity investment for the portfolio additions described below have been levelized for compatibility with the yearly asset analysis.

Table 4-9 shows some of the key results from our closed loop analysis of potential new generation additions to the base portfolios analyzed here. As shown, the addition of any of the proposed configurations of new NGCC generation would improve the expected mean annual financial performance of each of the three example generation portfolios. For example, the addition of 500 MW of new NGCC capacity to the Gas portfolio would increase the expected annual levelized cash flow from $674 million in the Gas portfolio case to $678 million. In addition, the addition of the proposed nuclear additions would be expected to dramatically improve the overall levelized return of the Coal portfolio. For example, the addition of a 1,000 MW of new nuclear capacity could improve the expected financial return form -$265 million to -$89 million.

Partially completed generating units

Another consideration for electric company planners may be the consideration of whether to complete a partially completed generation addition, such as a new nuclear unit. Some parties may wonder why this kind of analysis might be important. One reason this discussion is relevant is because fuel prices, specifically natural gas, are volatile, so a decision to build a nuclear plant, for example, under one set of market conditions may look favorable at that time. However, markets and fuel price outlooks can change drastically over the course of a long construction project and it is important to recognize that these types of mid-project evaluations are common and prudent.

As discussed above and shown in Table 4-9, it does not appear to make sense from a purely economic perspective in many of the cases analyzed here to construct a new nuclear unit based on the range of assumptions used in our illustrative analysis, because a new NGCC offers a better financial outcome based on expected future cash flow. However, as noted before, these results may be different based on different assumptions about the cost and performance of generation technologies, expected fuel prices (especially natural gas prices), electricity prices and other factors.

Table 4-9
Analysis of Incremental New Generation – "Closed Loop" Analysis Method

		Potential New Generation Capacity Additions					
Portfolio	**Mean Levelized Financial Return ($M/year)**	**+500 MW NGCC ($M/year)**	**+1000 MW NGCC ($M/year)**	**+2500 MW NGCC ($M/year)**	**+500 MW Nuclear ($M/year)**	**1000 MW Nuclear ($M/year)**	**2500 MW Nuclear ($M/year)**
Coal	-265	-231*	-198*	-96*	-152	-89	-169
Gas	674	678	682	694	640	604	502
Diverse	770	774	777	787	735	696	586
Note: * Less negative values imply reduced financial risk and better financial returns.							

Table 4-10 shows the results of our analysis of this situation. To do this, we assumed that an NGCCe or nuclear addition of either 500 MW, 1000 MW, or 2500 MW is 50% complete, and the owner is considering whether or not to complete construction based on the "closed loop" type of analysis described above.

Table 4-10
"Closed Loop" Analysis of New Capacity with 50% "Sunk" Capital Costs

		Potential New Generation Capacity Additions					
Portfolio	**Mean Levelized Financial Return ($M/yr)**	**+500 MW NGCC ($M/yr)**	**+1000 MW NGCC ($M/yr)**	**+2500 MW NGCC ($M/yr)**	**+500 MW Nuclear ($M/yr)**	**1000 MW Nuclear ($M/yr)**	**2500 MW Nuclear ($M/yr)**
Coal	-265	-231	-198	-96	-259	-263	-262
Gas	674	707	737	830	762	848	1051
Diverse	770	803	846	931	857	940	1196
Note: * less negative values imply reduced financial risk and better financial returns.							

The results shown in Table 4-10 suggest that it does make economic sense to complete any of the example new generation units, NGCC and nuclear, if they are 50% constructed based on the three portfolios shown. For all three portfolios – Coal, Gas and Diverse – completing any of the partially-constructed natural gas-fired or nuclear units would increase financial return.

However, a closer look at the data shown in Table 4-10 also shows that in an existing Coal portfolio it is only of marginal value to complete a half-built nuclear unit, whereas doing so starting from a Gas or Diverse asset portfolio would be expected to result in a substantial increase in return. For example, in the case of the Gas portfolio, the completion of a 1,000 MW partially-built nuclear unit would increases the return from $674 million from the Gas portfolio to $848 million with the addition of a new 1,000 MW nuclear generator.

Closed-loop analysis results

Based on our analyses, the addition of NGCCs and new nuclear generation to an "existing" asset portfolio can increase the portfolio asset value and sometimes reduce risk. The likelihood or probability of negative annual cash flow can decline when capacity additions add financial value, reduce risk or accomplish both. However, based on the specific financial, technology, performance, portfolio and power market assumptions underlying our analysis, it appears that only the addition of new NGCC capacity would enhance the expected levelized mean annual financial return expected from each of the three candidate portfolios.

However, our analysis results also suggest that if a significant fraction of the construction expenditures already have been incurred, then it makes economic sense to complete the construction of the partially-completed illustrative nuclear units analyzed here because doing so would increase the expected value of the cash flow associated with each of the example generation portfolios analyzed. Since the increase in expected profit per year is near zero, the example represents the approximate break-even fraction of unit completion (50%) that leads to a decision to continue construction in this case.

Finally, it is important to note that renewable technologies, such as wind generation, evaluated in this report do not appear to fare comparatively well based on our analyses, even though in some parts of the country electric companies have found renewable project developers have been willing to offer to develop renewable energy projects and provide electric power under long-term power purchase agreements (PPAs) at levels below "avoided costs." There are several reasons why the results shown here may not reflect these "real world" results. First, our analysis is designed to be illustrative only, and not definitive for a given region or set of technologies. Second, the cost and performance data used here for the renewables generation technologies may not be consistent with current actual cost and performance that may be achieved by some technologies or technology developers. Finally, the PPAs being negotiated today for renewable energy may reflect a situation where the "avoided cost" amount is determined through an administrative process that may not fully reflect the current state of the market for new renewable generation.

5
KEY INSIGHTS

This report builds on EPRI's work on this topic in 2013 that argued the "diversity challenge" is basically the same problem as "capacity expansion" – a challenge the electric power industry has faced since its inception. Capacity expansion plans can be evaluated using the same quantitative criteria that have been used traditionally by power planners and economists. The generation diversity challenge is a risk management challenge, so analysis of the value of diversity must rely on careful construction of scenarios and evaluation of candidate capacity expansion plans over the set of foreseeable futures.

The goal of phase two of this research was to gain further understanding of the financial value and risks associated with generation diversity, based on analysis of two scenarios: (i) the potential "green field" development of a *single power plant* when there is no other existing generation asset in the portfolio; and, (ii) the potential addition of new capacity to an existing electricity generation portfolio comprised of multiple generation assets. This report summarizes our analyses of these two scenarios and the lessons learned.

Currently, capacity additions in the U.S. electric industry are dominated by natural gas-fired generators and renewable power plants. The amount of natural gas based power plants being developed, and the dominance of new natural gas-fired capacity, has raised concerns among company executives, power planners and regulators. These concerns center on the extent to which the industry is "putting too many of its eggs into one basket." In more rigorous terms, some industry participants are questioning whether the amount of natural gas based power generation being added to the current generation fleet is leading to a lack of generation diversity.

EPRI's 2013 report on this topic made the case that this is an *economic problem* with a *risk management component*. The problem is economic because the important outcomes associated with decisions about generation additions are measured in changes in financial cost, profitability or other measures such as impacts on expected future customer rates. If adding a large amount of one kind of new power generation technology is a low-cost option that can be expected to lead to a better economic outcome (e.g., lower customer rates, increased profits, etc…), then companies and their customers may be less concerned about reducing technology diversity as part of making generation capacity additions.

In many cases, generation diversity does have value for reducing risk. This occurs because different technologies provide high value for different futures. To the extent that the averaging across the suite of scenarios drives the portfolio toward the mean, the risk as measured by the standard deviation will decline with increased diversity. The final decision on the best portfolio depends on both the risk and the return. While the reduced risk provided by diversity is valuable it must be considered in the context of the average return.

Stand-alone LCOE Analysis

In the "stand alone" power plant analysis described in section three, the key metric we used to determine the "best" new generation plant to build on a stand-alone basis was the expected LCOE. This is not the only measure that could be used to evaluate the potential net benefits of developing a new stand-alone power plant. For example, one could focus on measures of expected profitability, such as the expected net present value of the cash flows associated with the development of a new power plant.

Based on the Base case assumptions ($5.50/MMBtu natural gas price and $10/tonne CO_2 penalty, on a levelized basis and further described in sections three and four), new NGCC units are likely to be able to generate electricity for the lowest LCOE among the generation technologies evaluated in this report.

As part of our study, we conducted sensitivity analyses to examine which generation technology could be expected to produce the lowest LCOE when key underlying assumptions differ from those we used in our Base case. We analyzed the LCOE for each of the generation technologies based on different expected input fuel prices, expected CO_2 emissions costs, assumed capital costs and capacity factors.

Based on our sensitivity analyses, the lowest cost option from an LCOE perspective is the NGCC technology in several cases, <u>except</u> when natural gas prices are higher than used in the Base case ($8.80 v $5.50 per MMBtu). In this specific instance, new coal generation appears to offer the lowest levelized cost of electricity. However, the new coal plant specified in this analysis would <u>not</u> be allowed to be built if EPA finalizes its recently proposed 111(b) regulation for CO_2 emission from <u>new</u> fossil-fired generation sources. If this were the case, then the lowest cost of electricity would be provided by a new nuclear plant.

While new NGCC technology is favored from an LCOE perspective based on the technology and performance assumptions and commodity prices included in our Base case analysis, it is possible to construct analysis scenarios that favor each of the potential new generation technologies evaluated here, including NGCCs, coal, wind and nuclear generation.

In addition to the LCOE, electric companies, state regulators and other stakeholders may be interested in understanding how different proposed new generation technologies might impact a broader array of issues of concern. Some of these unquantified issues include: (i) fuel supply interruptions; (ii) tighter environmental regulations; (iii) fuel price volatility; (iv) investment size; and, (v) technology learning. The quantitative analyses described in this report did not attempt to quantify these issues in any way. Other EPRI research has studied some of these issues, and has produced a range of results from qualitative descriptions of the issues to numerical example calculations. In the real world, electric companies, regulators and other stakeholders are likely to be keenly aware of these issues, and addressing these issues in any specific situation may require new electric generation capacity to be developed that considers these other factors in the least total cost evaluation.

Open Loop Portfolio Analysis

The open loop analysis described in section four is based on the annual cash flows associated with each of the three asset portfolios analyzed in this report (i.e., Coal, Gas and Diverse), and is designed to evaluate how these cash flows may change with the addition of the “obligated” cash flows associated with acquisition or development of a new power generation asset. This open loop analysis may be of particular interest to corporate financial strategists and Chief Financial Officers (CFOs) because it provides insight into the expected changes to annual cash flow and associated financial risks that may result from the addition of new assets to a generation portfolio.

Based on our open loop analyses, the addition of new nuclear or NGCC generation capacity can be expected to improve the expected annual levelized cash flow for the Coal, Gas and Divers portfolios. However, our analysis illustrates that in many cases there is a tradeoff to be made between increasing expected cash flows and increasing financial risk and/or the probability of negative cash flows. In the case of the Coal portfolio several proposed generation additions offer increased overall economic performance. These “dominant” proposed additions can be expected to increase annual cash flow, reduce financial risk and reduce the probability of negative cash flow.

However, the open loop analysis is not complete. From the perspective of a company considering an *investment decision*, the financial analysis not only needs to include expected annual revenues and obligated expenses, but also needs to include the substantial shareholder equity the company would need to commit to build any new generation.

Closed Loop Portfolio Analysis

The critical difference between the open and closed loop cash flow analyses is that in the “closed loop” analysis, we account for all expected annual revenues and obligated expenses, but the closed-loop analysis also includes the 50% of the overnight capital costs associated with building new generation that we expect to be funded with shareholder equity rather than debt.

Based on our analyses and the specific range of financial, technology, performance, portfolio and power market assumptions underlying our analyses, it appears that only the addition of new NGCC capacity can be expected to enhance the expected levelized mean annual financial return from each of the three candidate portfolios.

However, the results from our analysis also suggest it makes economic sense to complete the constructions of partially-completed nuclear units analyzed here because doing so would increase the expected value of the cash flow associated with each of the example generation portfolios analyzed. The point during construction when it is attractive to complete a generation unit based on other technologies can be ascertained by doing similar analysis with the appropriate data inputs.

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U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis

Anthony Lopez, Billy Roberts, Donna Heimiller, Nate Blair, and Gian Porro

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

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Prepared under Task Nos. SA10.1012 and SA10.20A4

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Executive Summary

The National Renewable Energy Laboratory (NREL) routinely estimates the technical potential of specific renewable electricity generation technologies. These are technology-specific estimates of energy generation potential based on renewable resource availability and quality, technical system performance, topographic limitations, environmental, and land-use constraints only. The estimates do not consider (in most cases) economic or market constraints, and therefore do not represent a level of renewable generation that might actually be deployed.

This report is unique in unifying assumptions and application of methods employed to generate comparable estimates across technologies, where possible, to allow cross-technology comparison. Technical potential estimates for six different renewable energy technologies were calculated by NREL, and methods and results for several other renewable technologies from previously published reports are also presented. Table ES-1 summarizes the U.S. technical potential, in generation and capacity terms, of the technologies examined.

The report first describes the methodology and assumptions for estimating the technical potential of each technology, and then briefly describes the resulting estimates. The results discussion includes state-level maps and tables containing available land area (square kilometers), installed capacity (gigawatts), and electric generation (gigawatt-hours) for each technology.

Table ES-1. Total Estimated U.S. Technical Potential Generation and Capacity by Technology

Technology	Generation Potential (TWh)[a]	Capacity Potential (GW)[a]
Urban utility-scale PV	2,200	1,200
Rural utility-scale PV	280,600	153,000
Rooftop PV	800	664
Concentrating solar power	116,100	38,000
Onshore wind power	32,700	11,000
Offshore wind power	17,000	4,200
Biopower[b]	500	62
Hydrothermal power systems	300	38
Enhanced geothermal systems	31,300	4,000
Hydropower	300	60

[a] Non-excluded land was assumed to be available to support development of more than one technology.
[b] All biomass feedstock resources considered were assumed to be available for biopower use; competing uses, such as biofuels production, were not considered.

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Introduction

Renewable energy technical potential, as defined in this study, represents the achievable energy generation of a particular technology given system performance, topographic limitations, environmental, and land-use constraints. The primary benefit of assessing technical potential is that it establishes an upper-boundary estimate of development potential (DOE EERE 2006). It is important to understand that there are multiple types of potential—resource, technical, economic, and market—each seen in Figure 1 with its key assumptions.

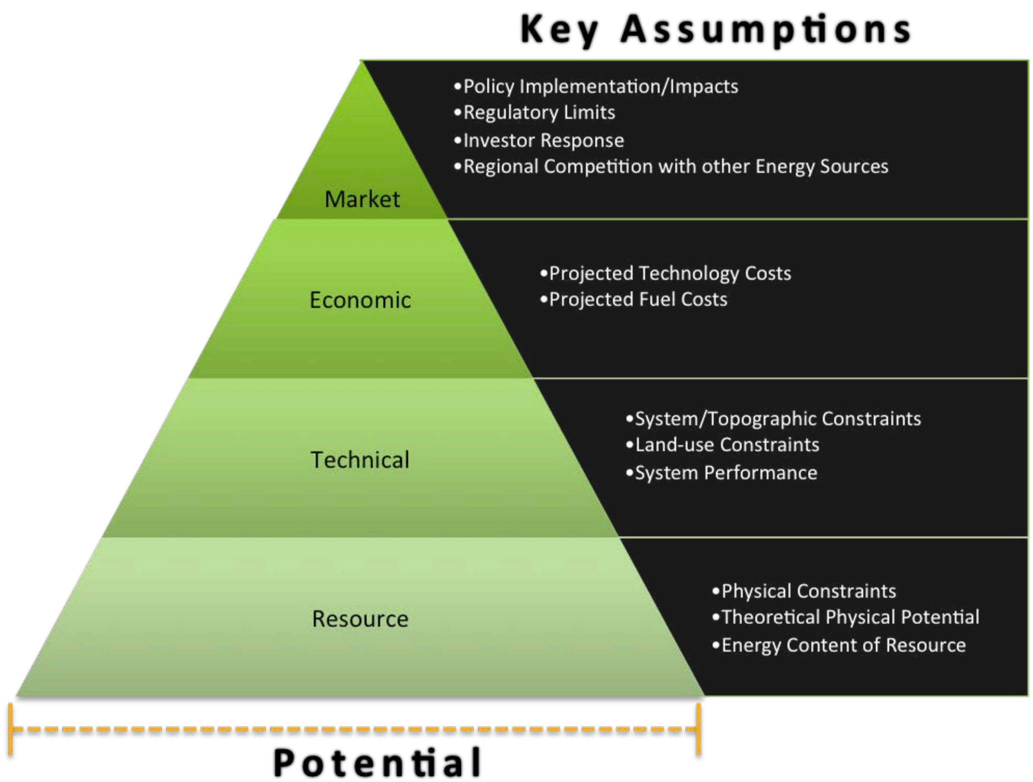

Figure 1. Levels of potential

Figure 1 is based on Table 4-1 in the 2011 update of DOE EERE (2006).

Although numerous studies have quantified renewable resource potential, comparing their results is difficult because of the different assumptions, methodologies, reporting units, and analysis time frames used (DOE EERE 2006). A national study of resource-based renewable energy technical potential across technologies has not been publicly available due to the challenges of unifying assumptions for all geographic areas and technologies (DOE EERE 2006).

This report presents the state-level results of a spatial analysis calculating renewable energy technical potential, reporting available land area (square kilometers), installed capacity (gigawatts), and electric generation (gigawatt-hours) for six different renewable electricity generation technologies: utility-scale photovoltaics (both urban and rural), concentrating solar power, onshore wind power, offshore wind power, biopower, and enhanced geothermal systems. Each technology's system-specific power density (or equivalent), capacity factor, and land-use constraints (Appendix A) were identified using published research, subject matter experts, and analysis by the National Renewable Energy Laboratory (NREL). System performance estimates rely heavily on NREL's Systems Advisor Model (SAM)[1] and Regional Energy Deployment System (ReEDS),[2] a multiregional, multi-time period, geographic information system (GIS) and linear programming model. This report also presents technical potential findings for rooftop photovoltaic, hydrothermal, and hydropower in a similar format based solely on previous published reports.

We provide methodological details of the analysis and references to the data sets used to ensure readers can directly assess the quality of data used, the data's underlying uncertainty, and impact of assumptions. While the majority of the exclusions applied for this analysis focus on evaluating technical potential, we include some economic exclusion criteria based on current commercial configuration standards to provide a more reasonable and conservative estimation of renewable resource potential.

Note that as a technical potential, rather than economic or market potential, these estimates do not consider availability of transmission infrastructure, costs, reliability or time-of-dispatch, current or future electricity loads, or relevant policies. Further, as this analysis does not allocate land for use by a particular technology, the same land area may be the basis for estimates of multiple technologies (i.e., non-excluded land is assumed to be available to support development of more than one technology).

Finally, since technical potential estimates are based in part on technology system performance, as these technologies evolve, their technical potential may also change.

[1] For more information, see http://sam.nrel.gov/.
[2] For more information, see http://www.nrel.gov/analysis/reeds/.

Analysis

Solar Power Technologies

Utility-Scale Photovoltaics (Urban)

We define urban utility-scale photovoltaics (PV) as large-scale PV deployed within urban boundaries on urban open space. The process for generating technical estimates for urban utility-scale PV begins with excluding areas not suitable for this technology. We first limit areas to those within urbanized area boundaries as defined by the U.S. Census Bureau (ESRI 2004) and further limit these areas to those with slopes less than or equal to 3%. Parking lots, roads, and urbanized areas are excluded by identifying areas with imperviousness greater than or equal to 1% (MRLC n.d.). Additional exclusions (Table A-1) are applied to eliminate areas deemed unlikely for development. The remaining land is grouped into contiguous areas and areas less than 18,000 square meters (m^2) are removed to ensure that total system size is large enough to be considered a utility-scale project.[3] This process produces a data set representative of the final available urban open space suitable for PV development. We obtain state-level annual capacity factors using the National Solar Radiation Database Typical Meteorological Year 3 (TMY3) data set (Wilcox, 2007; Wilcox and Marion, 2008) (Table A-2) and the SAM model. The PV system assumed in this analysis was a 1-axis tracking collector with the axis of rotation aligned north-south at 0 degrees tilt from the horizontal, which has a power density of 48 MW per square kilometer (MW/km^2) (Denholm and Margolis 2008a). State technical potential generation is expressed as:

$$State\ MWh = State \sum \left[urban\ openspace\ (km^2)\ \cdot power\ density\ \left(48 \frac{MW}{km^2}\right) \cdot state\ capacity\ factor\ (\%) \cdot 8760\ (hours\ per\ year)\right]$$

Utility-Scale Photovoltaics (Rural)

We define rural utility-scale PV as large-scale PV deployed outside urban boundaries (the complement of urban utility-scale PV). Technical potential estimates for rural utility-scale PV begin by first excluding urban areas as defined by the U.S. Census Bureau's urbanized area boundaries data set. We calculate percent slope for areas outside the urban boundaries and eliminate all areas with slopes greater than or equal to 3%. Federally protected lands, inventoried roadless areas, and areas of critical environmental concern are also excluded, as they are considered unlikely areas for development. Table A-3 contains the full list of exclusions. To limit the available lands to only larger PV systems, a 1-km^2 contiguous area filter was applied to produce a final available land layer. Finally, we calculate technical potential energy generation for this available land with the same annual average capacity factors, system design, and power density as for urban utility-scale PV, expressed as:

$$State\ MWh = State \sum \left[available\ land\ (km^2)\ \cdot power\ density\ \left(48 \frac{MW}{km^2}\right) \cdot state\ capacity\ factor\ (\%) \cdot 8760\ (hours\ per\ year)\right]$$

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[3] Depending on the PV system, 18,000 m^2 produces roughly a 1-MW system.

Rooftop Photovoltaics

We obtained rooftop PV estimates from Denholm and Margolis (2008b), who obtained floor space estimates for commercial and residential buildings from McGraw-Hill and scaled these to estimate a building footprint based on the number of floors. Average floor estimates were obtained from the Energy Information Administration's 2005 Residential Energy Consumption Survey (RECS) (DOE EIA 2005) and the 2003 Commercial Building Energy Consumption Survey (CBECS) (DOE EIA 2003). Denholm and Margolis (2008b) calculated roof footprint by dividing the building footprint by the number of floors. They estimated 8% of residential rooftops[4] and 63% of commercial rooftops[5] were flat. Orientations of pitched roofs were distributed uniformly. Usable roof area was extracted from total roof area using an availability factor that accounted for shading, rooftop obstructions, and constraints. Base estimates resulted in availability of 22% of roof areas for residential buildings in cool climates and 27% available in warm/arid climates. Denholm and Margolis (2008b) estimated commercial building availability at 60% for warm climates and 65% for cooler climates. Estimated average module efficiency was set at 13.5% with a power density for flat roofs of 110 W/m^2 and 135 W/m^2 for the rest. Denholm and Margolis (2008b) then aggregated state PV capacity to match Census Block Group populations; they then calculated capacity factors for the closest TMY station and applied these to the closest population group.

Concentrating Solar Power

We define concentrating solar power (CSP) as power from a utility-scale solar power facility in which the solar heat energy is collected in a central location. The technical potential estimates for CSP were calculated using satellite-modeled data from the National Solar Radiation Database (Wilcox, 2007), which represent annual average direct normal irradiance (DNI) as kilowatt-hours per square meter per day (kWh/m^2/day) from 1998 to 2005 at a 10-km horizontal spatial resolution. We consider viable only those areas with DNI greater than or equal to 5 kWh/m^2/day (Short et al. 2011).[6] Capacity factor values used in this analysis were generated for a trough system, dry-cooled with six hours of storage and a solar multiple[7] of 2, with a system power density of 32.8 MW/km^2.[8] The capacity factors for each resource class (Table A-4) are generated using the SAM model and TMY3. Land, slope, and contiguous area exclusions are consistent with rural utility-scale PV (Table A-3). Technical state energy generation was expressed as:

$$State\ MWh = State \sum \left[available\ land (km^2)\ \cdot power\ density\ \left(32.895 \frac{MW}{km^2}\right) \cdot state\ capacity\ factor\ (\%) \cdot 8760\ (hours\ per\ year)\right]$$

[4] Based on estimates from Navigant Consulting
[5] Based on Commercial Building Energy Consumption Survey (CBECS) database
[6] Technology improvements may lead to improved performance in the future that could affect this threshold.
[7] The field aperture area expressed as a multiple of the aperture area required to operate the power cycle at its design capacity.
[8] Craig Turchi, NREL CSP Analyst, personal communication

Wind Power Technologies

Onshore Wind Power

We define onshore wind power as wind resource at 80 meters (m) height above surface that results in an annual average gross[9] capacity factor of 30% (net capacity factor of 25.5%), using typical utility-scale wind turbine power curves. AWS Truepower modeled the wind resource data using its Mesomap® process to produce estimates at a 200-m horizontal spatial resolution. These resource estimates are processed to eliminate areas unlikely to be developed, such as urban areas, federally protected lands, and onshore water features, Table A-5 includes a full list of exclusions. We estimate annual generation by assuming a power density of 5 MW/km^2 (DOE EERE 2008)[10] and 15% energy losses to calculate net capacity factor.[11]

Offshore Wind Power

We define suitable offshore wind resource as annual average wind speed greater than or equal to 6.4 meters per second (m/s) at 90 m height above surface.[12] The offshore wind resource data consists of a composite of data sets modeled to estimate offshore wind potential generated by AWS Truepower for the Atlantic Coast from Maine to Massachusetts, Texas, Louisiana, Georgia, and the Great Lakes. Other areas are included using near-shore estimates from onshore-modeled wind resources from published research (Schwartz et al. 2010). Because no offshore or near-shore estimates were available for Florida or Alaska (at the time of this publication), these states are omitted from the technical potential calculations. The offshore resource data extend 50 nautical miles from shore, and in some cases have to be extrapolated to fill the extent (Schwartz et al. 2010). We further filter the resource estimates to eliminate shipping lanes, marine sanctuaries, and a variety of other areas deemed unlikely to be developed. Table A-8 contains a full list of exclusions. Our annual generation estimates assume a power density of 5 MW/km^2 and capacity factors based on wind speed interval and depth-based wind farm configurations to account for anchoring and stabilization for the turbines as developed by NREL analysts for use in the ReEDS model (Musial and Ram 2010).

Biopower Technologies

Biopower (Solid and Gaseous)

We obtained county-level estimates of solid biomass resource for crop, forest, primary/secondary mill residues, and urban wood waste from Milbrandt (2005, updated in 2008)[13] who reported the estimates in bone-dry tonnes (BDT) per year. We calculate technical potential energy generation assuming 1.1 MWh/BDT, which represents an average solid biomass system output with an industry-average conversion efficiency of

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[9] Gross capacity factor does not include plant downtime, parasitic power, or other factors that would be included to reduce the output to the "Net" capacity factor.
[10] Represents total footprint; disturbed footprint ranges from 2% to 5% of the total

[11] For more information, see http://www.windpoweringamerica.gov/wind_maps.asp.
[12] This is a typical wind turbine hub-height for offshore wind developments.

[13] For more information, see http://www.nrel.gov/gis/biomass.html.

20%, and a higher heating value (HHV) of 8,500 BTU/lb (Ince 1979). From Milbrandt (2005, partially updated in 2008),[14] we obtained county-level estimates of gaseous biomass (methane emissions), from animal manure, domestic wastewater treatment plants, and landfills; all estimates were reported in tonnes of methane (CH_4) per year. We calculate technical potential energy generation assuming 4.7 MWh/tonne of CH_4, which represents a typical gaseous biomass system output with an industry-average conversion efficiency of 30% (Goldstein et al), and a HHV of 24,250 BTU/lb. Other biomass resources (such as orchard/vineyard pruning's and black liquor) were not included in this study due to data limitations. Also, this analysis assumed that all biomass resources considered were available for biopower and did not evaluate competing uses such as biofuels production. The data from Milbrandt (2005, updated in 2008)[15] illustrates the biomass resource currently available in the United States. Subsequent revisions of this analysis could evaluate projected U.S. resource potential, including dedicated energy crops such as those provided by the recent U.S. DOE update (DOE 2011) of the billion-ton study (Perlack et al. 2005).

Geothermal Energy Technologies

Hydrothermal Power Systems

For identified hydrothermal and undiscovered hydrothermal, we used estimates from Williams et al. (2008), who estimated electric power generation potential of conventional geothermal resources (hydrothermal), both identified and unidentified in the western United States, Alaska, and Hawaii. Williams et al. derived total potential for identified hydrothermal resources by state from summations of volumetric models for the thermal energy and electric generation potential of each individual geothermal system (Muffler, 1979). For undiscovered hydrothermal estimates, we used resource estimates generated by Williams et al. (2009) that used logistic regression models of the western United States to estimate favorability of hydrothermal development and thus, to estimate undiscovered potential. In all cases, exclusions included public lands, such as national parks, that are not available for resource development.

Enhanced Geothermal Systems

We derive technical potential estimates for enhanced geothermal systems (EGS)[16] from temperature at depth data obtained from the Southern Methodist University's (SMU) Geothermal Laboratory.[17] The data ranged from 3 km to 10 km in depth. We consider viable those regions at each depth interval with temperatures ≥150°C. We apply known potential electric capacity (MW_e/km^3) to each temperature-depth interval to estimate total potential at each depth interval based on the total volume of each unique temperature-

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[14] For more information, see http://www.nrel.gov/gis/biomass.html.

[15] For more information, see http://www.nrel.gov/gis/biomass.html.

[16] Deep enhanced geothermal systems (EGS) are an experimental method of extracting energy from deep within the Earth's crust. This is achieved by fracturing hot dry rock between 3 and 10 kilometers (km) below the Earth's surface and pumping fluid into the fracture. The fluid absorbs the Earth's internal heat and is pumped back to the surface and used to generate electricity.

[17] Maria Richards, SMU Geothermal Laboratory, e-mail message to author, May 29, 2009. Data set featured in *The Future of Geothermal Energy* (MIT 2006)

depth interval, shown in Table A-10. Electric generation potential calculations summarize the technical potential (MW) at all depth intervals, electric generation potential (GWh) at all depth intervals with a 90% capacity factor, and annual electric generation potential (GWh) only at optimum depth. We determine optimum depth by a quantitative analysis[18] of levelized cost of electricity (LCOE). An optimum depth is found because drilling costs increase with depth while temperature, and therefore power plant efficiency, generally increase with depth so that power plant costs decrease with depth. Because drilling costs are increasing while power plant costs are decreasing on a per-MW basis, at some point there is a minimum. The optimum depth assumes that the EGS reservoir has a height or thickness of 1 km.

Hydropower Technologies

Hydropower

Source point locations of hydropower estimates were provided by the Idaho National Laboratory and were taken from Hall et al. (2006). The point locations were based on a previous study (Hall et al. 2004) that produced an assessment of gross power potential of every stream in the United States. To generate their own estimates, Hall et al. developed and used a feasibility study and development model. The feasibility study included additional economic potential criteria such as site accessibility, load or transmission proximity, along with technical potential exclusions of land use or environmental sensitivity. Sites meeting Hall et al. (2006) feasibility criteria were processed to produce power potential using a development model that did not require a dam or reservoir be built. The development model assumed only a low power (<1 MWa) or small hydro (>= 1 MWa and <= 30 MWa) plant would be built. To produce state technical potentials, we aggregated the previously mentioned source point locations to the state level.

[18] We used the quantitative analysis method from Augustine (2011).

Results

For each technology, we provide a brief summary of our findings along with a figure (map) showing the total estimated technical potential for all states and a table listing the total estimated technical potential by state.

Solar Power Technologies

Utility-Scale PV (Urban)

The total estimated annual technical potential in the United States for urban utility-scale PV is 2,232 terawatt-hours (TWh). Texas and California have the highest estimated technical potential, a result of a combination of good solar resource and large population. Figure 2 and Table 2 present the total estimated technical potential for urban utility-scale PV.

Utility-Scale PV (Rural)

Rural utility-scale PV leads all other technologies in technical potential. This is a result of relatively high power density, the absence of minimum resource threshold, and the availability of large swaths for development. Texas accounts for roughly 14% (38,993 TWh) of the entire estimated U.S. technical potential for utility-scale PV (280,613 TWh). Figure 3 and Table 3 present the total estimated technical potential for rural utility-scale PV.

Rooftop PV

Total annual technical potential for rooftop PV is estimated at 818 TWh. States with the largest technical potential typically have the largest populations. California has the highest technical potential of 106 TWh due to its mix of high population and relatively good solar resource. Figure 4 and Table 4 present the total estimated technical potential for rural utility-scale PV.

Concentrating Solar Power

Technical potential for CSP exists predominately in the Southwest. The steep cutoff of potential, as seen in Figure 5, can be attributed to the resource minimum threshold of 5 kWh/m2/day that was used in the analysis. Texas has the highest estimated potential of 22,786 TWh, which accounts for roughly 20% of the entire estimated U.S. annual technical potential for CSP (116,146 TWh). Figure 5 and Table 5 present the total estimated technical potential for concentrating solar power.

Wind Power Technologies

Onshore Wind Power

Technical potential for onshore wind power, which is present in nearly every state, is largest in the western and central Great Plains and lowest in the southeastern United States. While the wind resource intensity in the Great Plains is not as high as it is in some areas of the western United States, very little of the land area is excluded due to insufficient resource or due to other exclusions. In the eastern and western United States, the wind resource is more limited in coverage and is more likely to be impacted by environmental exclusions. Texas has the highest estimated annual potential of 5,552 TWh, which accounts for roughly 17% of the entire estimated U.S. annual technical potential for onshore wind (32,784 TWh). Figure 6 and Table 6 present the total estimated technical potential for onshore wind power.

Offshore Wind Power

Technical potential for offshore wind power is present in significant quantities in all offshore regions of the United States. Wind speeds off the Atlantic Coast and in the Gulf of Mexico are lower than they are off the Pacific Coast, but the presence of shallower waters there makes these regions more attractive for development. Hawaii has the highest estimated annual potential of 2,837 TWh, which accounts for roughly 17% of the entire estimated U.S. annual technical potential for offshore wind (16,975 TWh). Figure 7 and Table 7 present the total estimated technical potential for offshore wind power.

Biopower Technologies

Biopower (Solid and Gaseous)

Solid biomass accounts for 82% of the 400 TWh total estimated annual technical potential of biopower; of that, crop residues are the largest contributor. Gaseous biomass has an estimated annual technical potential of 88 TWh, of which landfills were the largest contributor. Figure 8 and Table 8 present the total estimated technical potential for biopower.

Geothermal Energy Technologies

Hydrothermal Power Systems

In the assessment, 71 TWh of electric power generation potential is the estimated total from existing (identified) hydrothermal sites spread among 13 states. An additional 237 TWh of undiscovered hydrothermal resources are estimated to exist among these same states. Figure 9 and Table 9 present the total estimated technical potential for hydrothermal power systems.

Enhanced Geothermal Systems

The vast majority of the geothermal potential for EGS (31,344 TWh) within the contiguous United States is located in the westernmost portion of the country. The Rocky Mountain States, and the Great Basin particularly, contain the most favorable resource for EGS (17,414 TWh). However, even the central and eastern portions of the country have 13,930 TWh of potential for EGS development. Note that, especially in western states, a considerable portion of the EGS resource occurs on protected land and was filtered out after exclusions were applied. Figure 10 and Table 10 present the total estimated technical potential for enhanced geothermal systems.

Hydropower Technologies

Hydropower

According to Hall et al. (2006), technical potential for hydropower exists predominately in the Northwest and Alaska with a combined total estimated at 69 TWh annually, which accounts for roughly 27% of the entire estimated U.S. annual technical potential for hydropower (259 TWh). Figure 11 and Table 11 present the total estimated technical potential for hydropower.

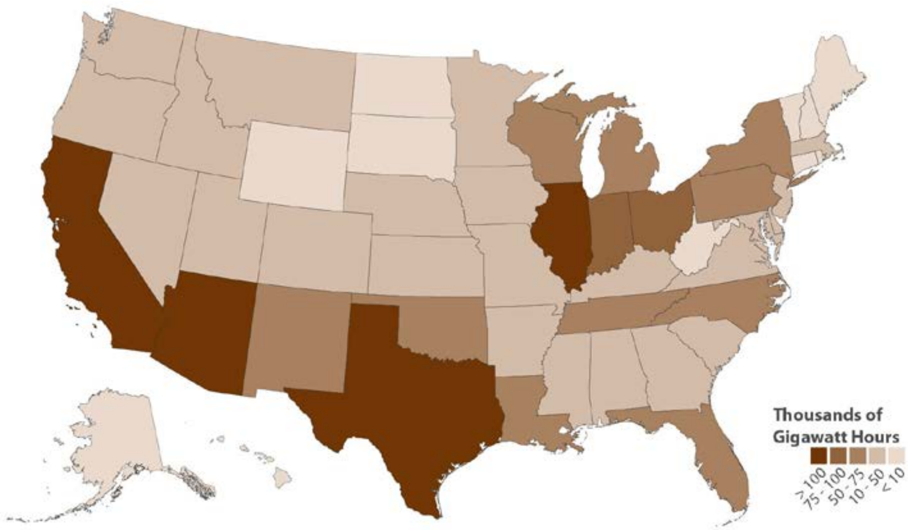

Figure 2. Total estimated technical potential for urban utility-scale photovoltaics in the United States

Table 2. Total Estimated Technical Potential for Urban Utility-Scale Photovoltaics by State[a]

State	KM^2	GW	GWh		State	KM^2	GW	GWh
Alabama	426	20	35,851		Montana	127	6	11,371
Alaska	2	<1	166		Nebraska	142	7	12,954
Arizona	1,096	53	121,306		Nevada	225	11	24,894
Arkansas	332	16	28,961		New Hampshire	49	2	3,790
California	2,321	111	246,008		New Jersey	527	25	44,307
Colorado	399	19	43,471		New Mexico	646	31	71,356
Connecticut	101	5	7,717		New York	683	33	52,803
Delaware	190	9	14,856		North Carolina	789	38	68,346
District of Columbia	<1	<1	8		North Dakota	57	3	4,871
Florida	830	40	72,787		Ohio	1,190	57	86,496
Georgia	506	24	43,167		Oklahoma	534	26	50,041
Hawaii	35	2	3,725		Oregon	271	13	25,783
Idaho	251	12	23,195		Pennsylvania	754	36	56,162
Illinois	1,325	64	103,552		Rhode Island	24	1	1,788
Indiana	1,274	61	98,815		South Carolina	398	19	33,835
Iowa	324	16	27,092		South Dakota	51	2	4,574
Kansas	317	15	31,706		Tennessee	596	29	50,243
Kentucky	339	16	26,515		Texas	3,214	154	294,684
Louisiana	675	32	55,669		Utah	293	14	30,492
Maine	40	2	3,216		Vermont	22	1	1,632
Maryland	379	18	28,551		Virginia	326	16	27,451
Massachusetts	228	11	17,470		Washington	402	19	33,690
Michigan	699	34	50,845		West Virginia	42	2	3,024
Minnesota	419	20	33,370		Wisconsin	728	35	54,939
Mississippi	318	15	26,366		Wyoming	75	4	7,232
Missouri	377	18	30,549		**U.S. Total**	**25,369**	**1,218**	**2,231,694**

[a] Non-excluded land was assumed to be available to support development of more than one technology.

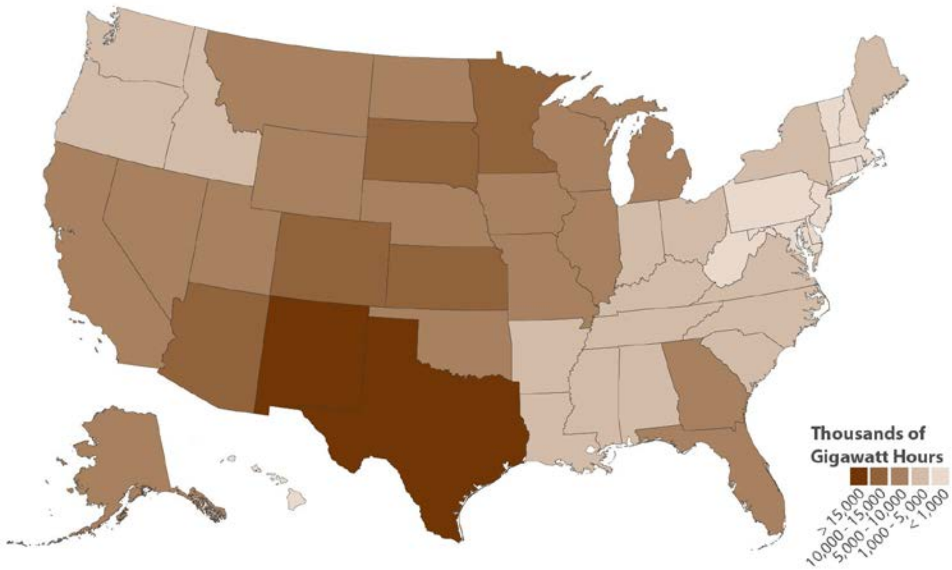

Figure 3. Total estimated technical potential for rural utility-scale photovoltaics in the United States

Table 3. Total Estimated Technical Potential for Rural Utility-Scale Photovoltaics by State[a]

State	KM²	GW	GWh
Alabama	44,058	2,115	3,706,839
Alaska	187,608	9,005	8,282,976
Arizona	107,231	5,147	11,867,694
Arkansas	57,239	2,747	4,986,389
California	83,549	4,010	8,855,917
Colorado	94,046	4,514	10,238,084
Connecticut	256	12	19,628
Delaware	3,483	167	272,333
District of Columbia	0	0	0
Florida	58,597	2,813	5,137,347
Georgia	64,343	3,088	5,492,183
Hawaii	431	21	38,033
Idaho	42,613	2,045	3,936,848
Illinois	103,524	4,969	8,090,985
Indiana	62,891	3,019	4,876,186
Iowa	83,763	4,021	6,994,159
Kansas	144,996	6,960	14,500,149
Kentucky	23,319	1,119	1,823,977
Louisiana	49,876	2,394	4,114,605
Maine	13,723	659	1,100,327
Maryland	7,773	373	585,949
Massachusetts	1,074	52	82,205
Michigan	71,741	3,444	5,215,640
Minnesota	135,627	6,510	10,792,814
Mississippi	59,997	2,880	4,981,252
Missouri	65,767	3,157	5,335,269
Montana	91,724	4,403	8,187,341
Nebraska	101,457	4,870	9,266,757
Nevada	77,751	3,732	8,614,454
New Hampshire	741	36	57,364
New Jersey	5,232	251	439,774
New Mexico	147,652	7,087	16,318,543
New York	19,294	926	1,492,566
North Carolina	48,892	2,347	4,232,790
North Dakota	114,228	5,483	9,734,448
Ohio	49,908	2,396	3,626,182
Oklahoma	99,641	4,783	9,341,920
Oregon	39,267	1,885	3,740,479
Pennsylvania	7,430	357	553,356
Rhode Island	184	9	13,636
South Carolina	32,399	1,555	2,754,973
South Dakota	111,350	5,345	10,008,873
Tennessee	26,396	1,267	2,225,990
Texas	425,230	20,411	38,993,582
Utah	49,797	2,390	5,184,878
Vermont	739	35	54,728
Virginia	22,378	1,074	1,882,467
Washington	20,759	996	1,738,151
West Virginia	729	35	52,694
Wisconsin	66,788	3,206	5,042,259
Wyoming	59,464	2,854	5,727,224
U.S. Total	**3,186,955**	**152,974**	**280,613,217**

[a] Non-excluded land was assumed to be available to support development of more than one technology.

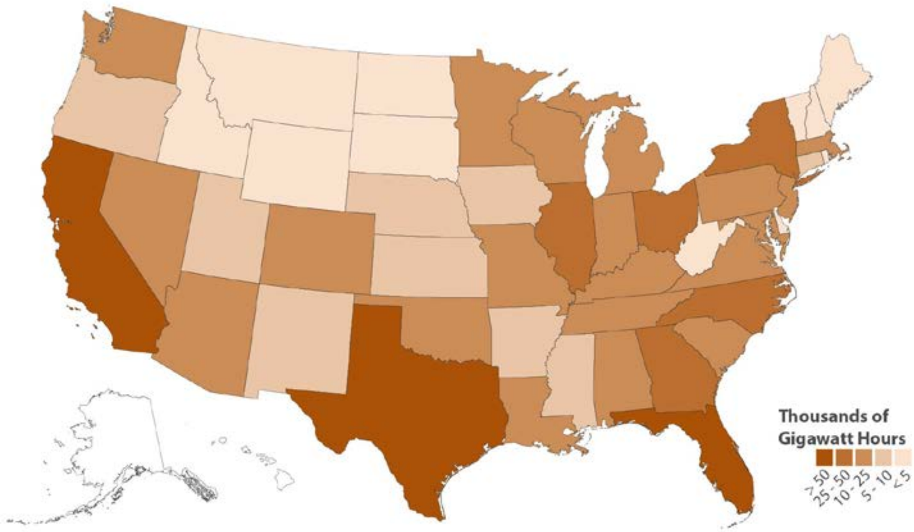

Figure 4. Total estimated technical potential for rooftop photovoltaics in the United States

Table 4. Total Estimated Technical Potential for Rooftop Photovoltaics by State[a]

State	GW	GWh	State	GW	GWh
Alabama	13	15,476	Montana	2	2,194
Alaska	1	NA	Nebraska	4	5,337
Arizona	15	22,736	Nevada	7	10,767
Arkansas	7	8,485	New Hampshire	2	2,299
California	76	106,411	New Jersey	14	15,768
Colorado	12	16,162	New Mexico	4	6,513
Connecticut	6	6,616	New York	25	28,780
Delaware	2	2,185	North Carolina	23	28,420
District of Columbia	2	2,490	North Dakota	2	1,917
Florida	49	63,987	Ohio	27	30,064
Georgia	25	31,116	Oklahoma	9	12,443
Hawaii	3	NA	Oregon	8	8,323
Idaho	3	4,051	Pennsylvania	20	22,215
Illinois	26	30,086	Rhode Island	2	1,711
Indiana	15	17,151	South Carolina	12	14,413
Iowa	7	8,646	South Dakota	2	2,083
Kansas	7	8,962	Tennessee	16	19,685
Kentucky	11	12,312	Texas	60	78,717
Louisiana	12	14,368	Utah	6	7,514
Maine	2	2,443	Vermont	1	1,115
Maryland	13	14,850	Virginia	19	22,267
Massachusetts	10	11,723	Washington	13	13,599
Michigan	22	23,528	West Virginia	4	4,220
Minnesota	12	14,322	Wisconsin	12	13,939
Mississippi	7	8,614	Wyoming	1	1,551
Missouri	13	16,160	**U.S. Total**	**664**	**818,733**

[a] Non-excluded land was assumed to be available to support development of more than one technology.

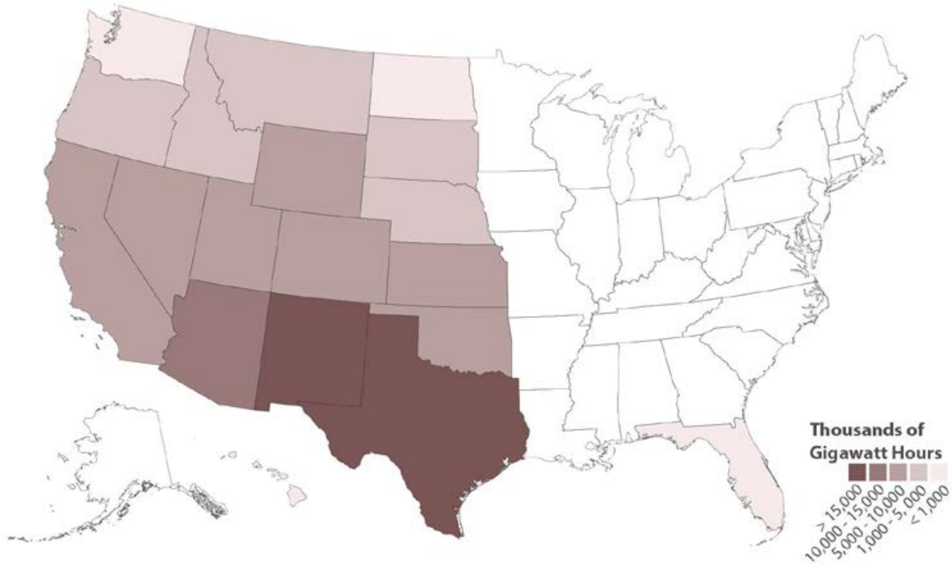

Figure 5. Total estimated technical potential for concentrating solar power in the United States

Table 5. Total Estimated Technical Potential for Concentrating Solar Power by State[a]

State	KM^2	GW	GWh			KM^2	GW	GWh
Alabama	0	0	0		Montana	16,939	557	1,540,288
Alaska	0	0	0		Nebraska	53,305	1,753	4,846,929
Arizona	107,239	3,528	12,544,334		Nevada	77,760	2,558	8,295,753
Arkansas	0	0	0		New Hampshire	0	0	0
California	82,860	2,726	8,490,916		New Jersey	0	0	0
Colorado	94,173	3,098	9,154,524		New Mexico	147,748	4,860	16,812,349
Connecticut	0	0	0		New York	0	0	0
Delaware	0	0	0		North Carolina	0	0	0
District of Columbia	0	0	0		North Dakota	396	13	36,050
Florida	4	0	359		Ohio	0	0	0
Georgia	0	0	0		Oklahoma	55,113	1,813	5,068,036
Hawaii	168	6	15,370		Oregon	30,927	1,017	2,812,126
Idaho	38,523	1,267	3,502,877		Pennsylvania	0	0	0
Illinois	0	0	0		Rhode Island	0	0	0
Indiana	0	0	0		South Carolina	0	0	0
Iowa	0	0	0		South Dakota	17,922	590	1,629,660
Kansas	87,698	2,885	7,974,256		Tennessee	0	0	0
Kentucky	0	0	0		Texas	235,398	7,743	22,786,750
Louisiana	0	0	0		Utah	49,799	1,638	5,067,547
Maine	0	0	0		Vermont	0	0	0
Maryland	0	0	0		Virginia	0	0	0
Massachusetts	0	0	0		Washington	1,778	59	161,713
Michigan	0	0	0		West Virginia	0	0	0
Minnesota	0	0	0		Wisconsin	0	0	0
Mississippi	0	0	0		Wyoming	59,457	1,956	5,406,407
Missouri	0	0	0		**U.S. Total**	**1,157,209**	**38,066**	**116,146,245**

[a] Non-excluded land was assumed to be available to support development of more than one technology.

Figure 6. Total estimated technical potential for onshore wind power in the United States

Table 6. Total Estimated Technical Potential for Onshore Wind Power by State[a]

State	KM²	GW	GWh		State	KM²	GW	GWh
Alabama	24	<1	283		Montana	188,801	944	2,746,272
Alaska	98,669	493	1,373,433		Nebraska	183,600	918	3,011,253
Arizona	2,181	11	26,036		Nevada	1,449	7	17,709
Arkansas	1,840	9	22,892		New Hampshire	427	2	5,706
California	6,822	34	89,862		New Jersey	26	<1	317
Colorado	77,444	387	1,096,036		New Mexico	98,417	492	1,399,157
Connecticut	5	<1	62		New York	5,156	26	63,566
Delaware	2	<1	22		North Carolina	162	<1	2,037
District of Columbia	0	0	0		North Dakota	154,039	770	2,537,825
Florida	<1	<1	<1		Ohio	10,984	55	129,143
Georgia	26	<1	323		Oklahoma	103,364	517	1,521,652
Hawaii	494	2	7,787		Oregon	5,420	27	68,767
Idaho	3,615	18	44,320		Pennsylvania	661	3	8,231
Illinois	49,976	250	649,468		Rhode Island	9	<1	130
Indiana	29,646	148	377,604		South Carolina	37	<1	428
Iowa	114,143	571	1,723,588		South Dakota	176,483	882	2,901,858
Kansas	190,474	952	3,101,576		Tennessee	62	<1	766
Kentucky	12	<1	147		Texas	380,306	1,902	5,552,400
Louisiana	82	<1	935		Utah	2,621	13	31,552
Maine	2,250	11	28,743		Vermont	590	3	7,796
Maryland	297	1	3,632		Virginia	359	2	4,589
Massachusetts	206	1	2,827		Washington	3,696	18	47,250
Michigan	11,808	59	143,908		West Virginia	377	2	4,952
Minnesota	97,854	489	1,428,525		Wisconsin	20,751	104	255,266
Mississippi	0	0	0		Wyoming	110,415	552	1,653,857
Missouri	54,871	274	689,519		**U.S. Total**	**2,190,952**	**10,955**	**32,784,004**

[a] Non-excluded land was assumed to be available to support development of more than one technology.

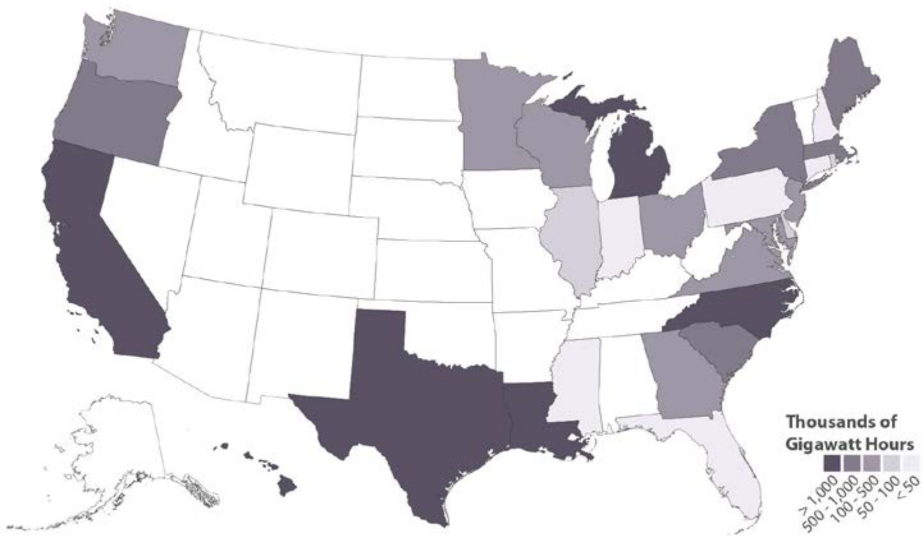

Figure 7. Total estimated technical potential for offshore wind power in the United States

Table 7. Total Estimated Technical Potential for Offshore Wind Power by State[a]

State	KM²	GW	GWh		State	KM²	GW	GWh
Alabama	0	0	0		Montana	NA	NA	NA
Alaska	NA	NA	NA		Nebraska	NA	NA	NA
Arizona	NA	NA	NA		Nevada	NA	NA	NA
Arkansas	NA	NA	NA		New Hampshire	691	3	14,478
California	130,967	655	2,662,580		New Jersey	20,387	102	429,808
Colorado	NA	NA	NA		New Mexico	NA	NA	NA
Connecticut	1,434	7	26,545		New York	29,215	146	614,280
Delaware	3,008	15	60,654		North Carolina	61,204	306	1,269,627
District of Columbia	NA	NA	NA		North Dakota	NA	NA	NA
Florida	1,930	10	34,684		Ohio	8,361	42	170,561
Georgia	11,726	59	220,807		Oklahoma	NA	NA	NA
Hawaii	147,389	737	2,836,735		Oregon	45,002	225	962,723
Idaho	NA	NA	NA		Pennsylvania	1,135	6	23,571
Illinois	3,174	16	66,070		Rhode Island	4,193	21	89,115
Indiana	9	<1	166		South Carolina	26,643	133	542,218
Iowa	NA	NA	NA		South Dakota	NA	NA	NA
Kansas	NA	NA	NA		Tennessee	NA	NA	NA
Kentucky	NA	NA	NA		Texas	54,289	271	1,101,063
Louisiana	68,123	341	1,200,699		Utah	NA	NA	NA
Maine	29,484	147	631,960		Vermont	NA	NA	NA
Maryland	10,382	52	200,852		Virginia	17,815	89	361,054
Massachusetts	36,815	184	799,344		Washington	24,193	121	488,025
Michigan	84,515	423	1,739,801		West Virginia	NA	NA	NA
Minnesota	5,843	29	100,455		Wisconsin	16,134	81	317,755
Mississippi	643	3	10,172		Wyoming	NA	NA	NA
Missouri	NA	NA	NA		**U.S. Total**	**844,703**	**4,223**	**16,975,802**

[a] Non-excluded land was assumed to be available to support development of more than one technology.

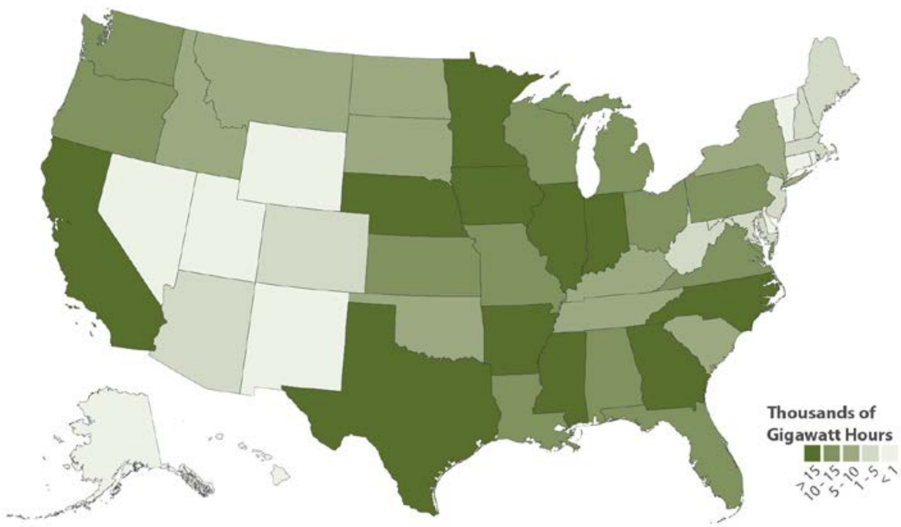

Figure 8. Total estimated technical potential for biopower in the United States

Table 8. Total Estimated Technical Potential for Biopower by State[a]

State	GW	GWh		State	GW	GWh
Alabama	2	12,727		Montana	<1	5,072
Alaska	<1	575		Nebraska	2	17,023
Arizona	<1	1,925		Nevada	<1	614
Arkansas	2	15,444		New Hampshire	<1	1,343
California	4	27,919		New Jersey	<1	3,523
Colorado	<1	4,138		New Mexico	<1	949
Connecticut	<1	909		New York	1	8,509
Delaware	<1	898		North Carolina	2	16,650
District of Columbia	<1	66		North Dakota	1	8,216
Florida	2	13,358		Ohio	2	14,372
Georgia	2	16,903		Oklahoma	<1	5,094
Hawaii	<1	724		Oregon	2	14,684
Idaho	<1	5,958		Pennsylvania	2	13,446
Illinois	4	31,960		Rhode Island	<1	618
Indiana	2	17,920		South Carolina	1	8,415
Iowa	4	28,928		South Dakota	1	8,615
Kansas	2	12,857		Tennessee	1	8,080
Kentucky	1	8,322		Texas	3	21,976
Louisiana	2	14,873		Utah	<1	862
Maine	<1	4,398		Vermont	<1	695
Maryland	<1	3,329		Virginia	1	10,365
Massachusetts	<1	2,149		Washington	2	13,826
Michigan	2	11,897		West Virginia	<1	2,688
Minnesota	3	21,391		Wisconsin	2	13,295
Mississippi	2	15,287		Wyoming	<1	553
Missouri	2	13,986		**U.S. Total**	**62**	**488,326**

[a] Non-excluded land was assumed to be available to support development of more than one technology. All biomass feedstock resources considered were assumed to be available for biopower use; competing uses, such as biofuels production, were not considered.

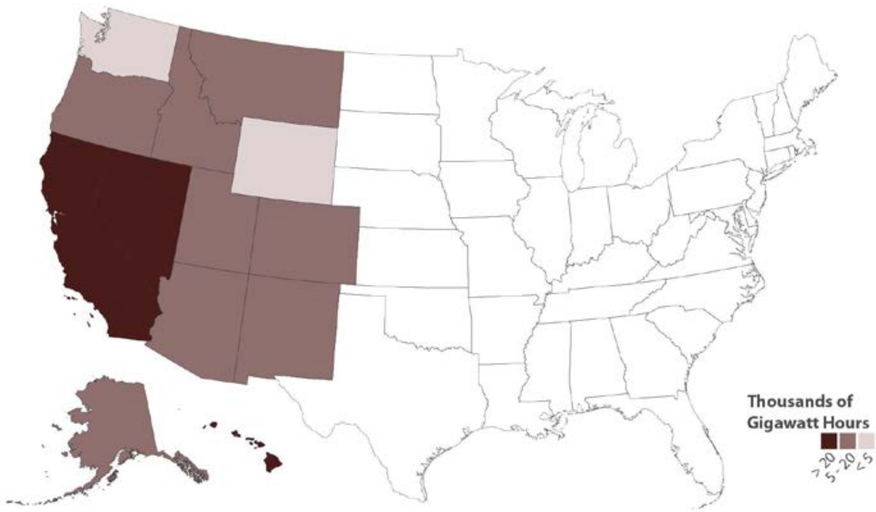

Figure 9. Total estimated technical potential for hydrothermal power in the United States

Table 9. Total Estimated Technical Potential for Hydrothermal Power by State[a]

State	GW	GWh		State	GW	GWh
Alabama	<1	<1		Montana	<1	6,548
Alaska	2	15,437		Nebraska	<1	<1
Arizona	1	8,330		Nevada	6	45,321
Arkansas	<1	<1		New Hampshire	<1	<1
California	17	130,921		New Jersey	<1	<1
Colorado	1	8,954		New Mexico	2	12,933
Connecticut	<1	<1		New York	<1	<1
Delaware	<1	<1		North Carolina	<1	<1
District of Columbia	<1	<1		North Dakota	<1	<1
Florida	<1	<1		Ohio	<1	<1
Georgia	<1	<1		Oklahoma	<1	<1
Hawaii	3	20,632		Oregon	2	18,200
Idaho	2	17,205		Pennsylvania	<1	<1
Illinois	<1	<1		Rhode Island	<1	<1
Indiana	<1	<1		South Carolina	<1	<1
Iowa	<1	<1		South Dakota	<1	<1
Kansas	<1	<1		Tennessee	<1	<1
Kentucky	<1	<1		Texas	<1	<1
Louisiana	<1	<1		Utah	2	12,982
Maine	<1	<1		Vermont	<1	<1
Maryland	<1	<1		Virginia	<1	<1
Massachusetts	<1	<1		Washington	<1	2,547
Michigan	<1	<1		West Virginia	<1	<1
Minnesota	<1	<1		Wisconsin	<1	<1
Mississippi	<1	<1		Wyoming	<1	1,373
Missouri	<1	<1		**U.S. Total**	**38**	**308,156**

[a] Non-excluded land was assumed to be available to support development of more than one technology.

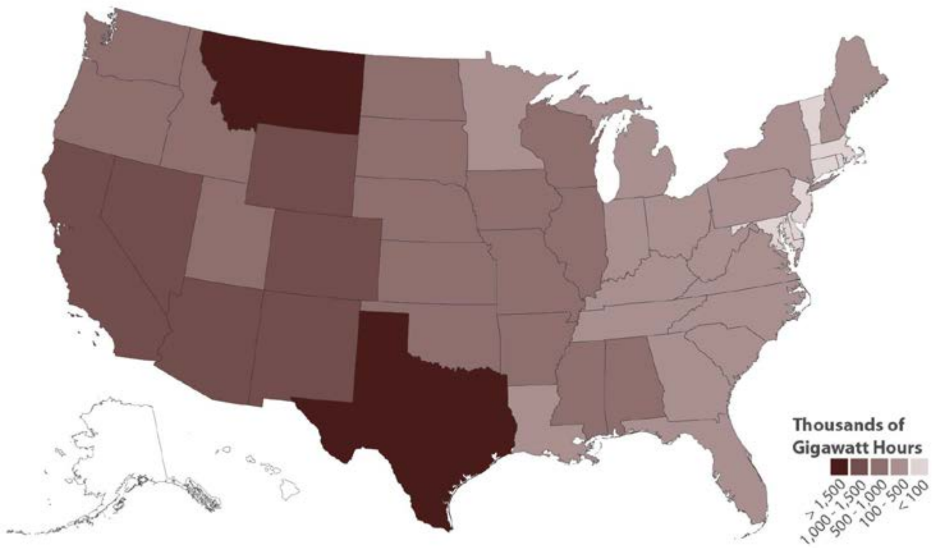

Figure 10. Total estimated technical potential for enhanced geothermal systems in the United States

Table 10. Total Estimated Technical Potential for Enhanced Geothermal Systems by State[a]

State	GW	GWh		State	GW	GWh
Alabama	68	535,490		Montana	209	1,647,304
Alaska	NA	NA		Nebraska	118	927,996
Arizona	157	1,239,148		Nevada	160	1,262,175
Arkansas	80	628,622		New Hampshire	13	104,314
California	170	1,344,179		New Jersey	4	35,230
Colorado	159	1,251,658		New Mexico	180	1,417,978
Connecticut	7	56,078		New York	48	375,401
Delaware	3	22,813		North Carolina	53	420,741
District of Columbia	<1	698		North Dakota	104	820,226
Florida	47	374,161		Ohio	63	495,922
Georgia	45	353,206		Oklahoma	99	779,667
Hawaii	NA	NA		Oregon	116	914,105
Idaho	126	993,257		Pennsylvania	42	327,341
Illinois	86	676,056		Rhode Island	1	11,492
Indiana	55	434,258		South Carolina	46	364,105
Iowa	77	606,390		South Dakota	117	921,973
Kansas	126	989,676		Tennessee	54	428,380
Kentucky	61	484,659		Texas	384	3,030,251
Louisiana	61	484,271		Utah	119	939,381
Maine	48	377,075		Vermont	5	35,617
Maryland	11	86,649		Virginia	37	290,737
Massachusetts	12	92,227		Washington	71	563,024
Michigan	58	457,850		West Virginia	33	261,376
Minnesota	47	369,785		Wisconsin	82	647,173
Mississippi	71	559,056		Wyoming	136	1,070,079
Missouri	106	835,445		**U.S. Total**	**3,976**	**31,344,696**

[a] Non-excluded land was assumed to be available to support development of more than one technology.

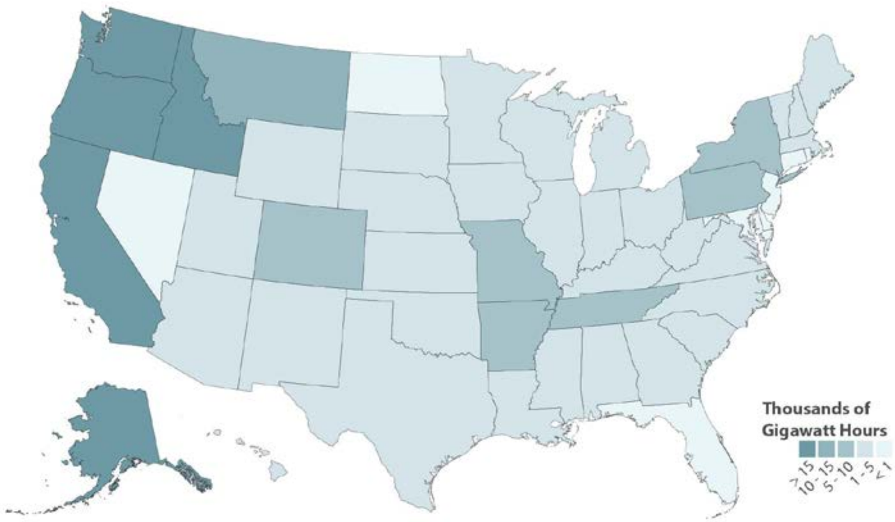

Figure 11. Total estimated technical potential for hydropower in the United States

Table 11. Total Estimated Technical Potential for Hydropower by State[a]

State	Count	GW	GWh		State	Count	GW	GWh
Alabama	2,435	<1	4,103		Montana	6,859	3	14,547
Alaska	3,053	5	23,676		Nebraska	2,880	<1	3,142
Arizona	1,958	<1	1,303		Nevada	1,489	<1	846
Arkansas	3,268	1	6,093		New Hampshire	810	<1	1,741
California	9,692	7	30,024		New Jersey	402	<1	549
Colorado	5,060	2	7,789		New Mexico	1,810	<1	1,363
Connecticut	659	<1	922		New York	4,839	2	6,711
Delaware	25	<1	31		North Carolina	2,131	<1	3,037
District of Columbia	2	<1	<1		North Dakota	572	<1	347
Florida	493	<1	682		Ohio	1,791	<1	3,046
Georgia	2,100	<1	1,988		Oklahoma	2,824	<1	3,016
Hawaii	437	<1	2,602		Oregon	7,993	4	18,184
Idaho	6,706	4	18,758		Pennsylvania	4,466	2	8,368
Illinois	1,330	1	4,883		Rhode Island	86	<1	59
Indiana	1,142	<1	2,394		South Carolina	889	<1	1,889
Iowa	2,398	<1	2,818		South Dakota	1,712	<1	1,047
Kansas	3,201	<1	2,508		Tennessee	2,610	1	5,745
Kentucky	1,394	<1	4,255		Texas	4,366	<1	3,006
Louisiana	934	<1	2,423		Utah	3,394	<1	3,528
Maine	1,373	<1	3,916		Vermont	1,207	<1	1,710
Maryland	491	<1	814		Virginia	2,601	<1	3,657
Massachusetts	560	<1	1,197		Washington	7,310	6	27,249
Michigan	1,942	<1	1,181		West Virginia	1,711	1	4,408
Minnesota	1,391	<1	1,255		Wisconsin	1,863	1	2,287
Mississippi	1,536	<1	2,211		Wyoming	2,842	1	4,445
Missouri	5,089	2	7,198		**U.S. Total**	**128,126**	**60**	**258,953**

[a] Non-excluded land was assumed to be available to support development of more than one technology.

Discussion

Table 12 summarizes the estimated technical generation and capacity potential in the Unites States for each renewable electricity technology examined in this report. As estimates of technical, rather than economic or market, potential, these values do not consider:

- Allocation of available land among technologies (available land is generally assumed to be available to support development of more than one technology and each set of exclusions was applied independently)
- Availability of existing or planned transmission infrastructure that is necessary to tie generation into the electricity grid
- The relative reliability or time-of-productions of power
- The cost associated with developing power at any location
- Presence of local, state, regional or national policies, either existing or potential, that could encourage renewable development
- The location or magnitude of current and potential electricity loads.

While not a direct comparison, given the above considerations, one useful point of reference for the generation potential estimate is annual electricity retail sales in the United States. In 2010, aggregate sales for all 50 states were roughly 3,754 TWh (see Appendix B).

Table 12. Total Estimated Technical Potential Generation and Capacity by Technology

Technology	Generation Potential (TWh)[a]	Capacity Potential (GW)[a]
Urban utility-scale PV	2,200	1,200
Rural utility-scale PV	280,600	153,000
Rooftop PV	800	664
Concentrating solar power	116,100	38,000
Onshore wind power	32,700	11,000
Offshore wind power	17,000	4,200
Biopower[b]	500	62
Hydrothermal power systems	300	38
Enhanced geothermal systems	31,300	4,000
Hydropower	300	60

[a] Non-excluded land was assumed to be available to support development of more than one technology.
[b] All biomass feedstock resources considered were assumed to be available for biopower use; competing uses, such as biofuels production, were not considered.

Updates to these technical potentials are possible on an ongoing basis as resource, system, exclusions and domain knowledge change and data sets improve in quality and resolution. In this study, we identified areas of potential improvements that include the acquisition of localized PV capacity factors, updated exclusion layers, and the use of updated land-cover data sets.

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Appendix A. Exclusions and Constraints, Capacity Factors, and Power Densities

Table A-1. Exclusions and Constraints for Urban Utility-Scale Photovoltaics

Slope Exclusion	> 3%	
Contiguous Area Exclusion	< 0.018 km^2	
Land Type(s) Exclusion	Within Urban Boundaries	ESRI (2004)
	Landmarks	ESRI (2007a)
	Parks	ESRI (2007b)
	MRLC - Water	MRLC (n.d.)
	MRLC - Wetlands	MRLC (n.d.)
	MRLC - Forests	MRLC (n.d.)
	MRLC -Impervious Surface >= 1%	MRLC (n.d.)

Table A-2. Capacity Factors for Utility-Scale Photovoltaics[a]

State	Capacity Factor	State	Capacity Factor	State	Capacity Factor
Alabama	0.200	Maine	0.191	Oklahoma	0.223
Alaska	0.105	Maryland	0.179	Oregon	0.227
Arizona	0.263	Massachusetts	0.182	Pennsylvania	0.177
Arkansas	0.207	Michigan	0.173	Rhode Island	0.176
California	0.252	Minnesota	0.189	South Carolina	0.202
Colorado	0.259	Mississippi	0.197	South Dakota	0.214
Connecticut	0.182	Missouri	0.193	Tennessee	0.201
Delaware	0.186	Montana	0.212	Texas	0.218
Florida	0.209	Nebraska	0.217	Utah	0.248
Georgia	0.203	Nevada	0.263	Vermont	0.176
Hawaii	0.210	New Hampshire	0.184	Virginia	0.200
Idaho	0.220	New Jersey	0.200	Washington	0.199
Illinois	0.186	New Mexico	0.263	West Virginia	0.172
Indiana	0.184	New York	0.184	Wisconsin	0.180
Iowa	0.199	North Carolina	0.206	Wyoming	0.229
Kansas	0.238	North Dakota	0.203		
Kentucky	0.186	Ohio	0.173		
Louisiana	0.196				

[a] (SAM)

Table A-3. Exclusions and Constraints for Rural Utility-Scale Photovoltaics and Concentrating Solar Power

Slope Exclusion	> 3%	
Contiguous Area Exclusion	< 1 km^2	
Land Type(s) Exclusion	Urban Areas	ESRI (2004)
	MRLC - Water	MRLC (n.d.)
	MRLC - Wetlands	MRLC (n.d.)
	BLM ACEC Lands (Areas of Critical Environmental Concern) (BLM 2009)	BLM (2009)
	Forest Service IRA (Inventoried Roadless Area) (USFS 2003)	USFS (2003)
	National Park Service Lands	USGS (2005)
	Fish & Wildlife Lands	USGS (2005)
	Federal Parks	USGS (2005)
	Federal Wilderness	USGS (2005)
	Federal Wilderness Study Area	USGS (2005)
	Federal National Monument	USGS (2005)
	Federal National Battlefield	USGS (2005)
	Federal Recreation Area	USGS (2005)
	Federal National Conservation Area	USGS (2005)
	Federal Wildlife Refuge	USGS (2005)
	Federal Wildlife Area	USGS (2005)
	Federal Wild and Scenic Area	USGS (2005)

Table A-4. Capacity Factors for Concentrating Solar Power[a]

Class	Kwh/m2/day	Capacity Factor
1	5–6.25	0.315
2	6.25–7.25	0.393
3	7.25–7.5	0.428
4	7.5–7.75	0.434
5	> 7.75	0.448

[a] (SAM)

Table A-5. Exclusions and Constraints for Onshore Wind Power

Slope Exclusion	> 20%	
Distance Exclusion	< 3 km Distance to Excluded Area (does not apply to water)	
Land Type(s) Exclusion	50% Forest Service Lands (includes National Grasslands, excludes ridge crests)	USGS (2005)
	50% Department of Defense Lands (excludes ridge crest)	USGS (2005)
	50% GAP Land Stewardship Class 2 - Forest	CBI (2004)
	50% Exclusion of non-ridge crest forest (non-cumulative over Forest Service Land)	USGS (2005)
	Airports	ESRI (2003)
	Urban Areas	ESRI (2004)
	LULC - Wetlands	USGS (1993)
	LULC - Water	USGS (1993)
	Forest Service IRA (Inventoried Roadless Areas)	USFS (2003)
	National Park Service Lands	USGS (2005)
	Fish & Wildlife Lands	USGS (2005)
	Federal Parks	USGS (2005)
	Federal Wilderness	USGS (2005)
	Federal Wilderness Study Area	USGS (2005)
	Federal National Monument	USGS (2005)
	Federal National Battlefield	USGS (2005)
	Federal Recreation Area	USGS (2005)
	Federal National Conservation Area	USGS (2005)
	Federal Wildlife Refuge	USGS (2005)
	Federal Wildlife Area	USGS (2005)
	Federal Wild and Scenic Area	USGS (2005)
	GAP Land Stewardship Class 2 - State & Private Lands Equivalent to Federal Exclusions	CBI (2004)

Table A-6. Capacity Factor for Offshore Wind Power[a]

Depth	Class	Watts/m^2	Capacity Factor
Shallow			
0–30 meters	3	300–400	0.36
0–30 meters	4	400–500	0.39
0–30 meters	5	500–600	0.45
0–30 meters	6	600–800	0.479
0–30 meters	7	> 800	0.5
Deep			
> 30 meters	3	300–400	0.367
> 30 meters	4	400–500	0.394
> 30 meters	5	500–600	0.45
> 30 meters	6	600–800	0.479
> 30 meters	7	> 800	0.5

[a] (ReEDS)

Table A-7. Conversion of Offshore Wind Speeds at 90 Meters to Power Classes[a]

Wind Speed (meters / second)	Power Class
6.4–7.0	3
7 .0–7.5	4
7.5–8.0	5
8.0–8.8	6
> 8.8	7

[a] Marc Schwartz, NREL Wind Analyst, personal communication

Table A-8. Exclusions and Constraints for Offshore Wind Power[a]

Distance Exclusion	< 50 nautical miles from shoreline
Land Type(s) Exclusion	
Federal Exclusions	National Marine Sanctuaries
	Marine Protected Areas Inventory – 'NAL', 'NIL', 'NTL'
	Office of Habitat Conservation Habitat Protection Div. EFH – Shipping Routes, Sanctuary Protected Areas
	NOAA Jurisdictional Boundaries and Limits – Coastal National Wildlife Refuges – Pacific
	Navigational & Marine Infrastructure – Shipping Lanes, Drilling Platforms (Gulf), Pipelines (Gulf), Fairways (Gulf)
	NWIOOS – Towlane Agreement WSG 2007
	World Database on Protected Areas Annual Release 2009 Global Data set – Offshore Oil & Gas Pipelines/Drilling Platforms
Texas	Pipelines & Easements
	Audubon Sanctuaries
	Gulf Inter-coastal Waterway/Ship Channels
	National Wildlife Refuges
	Shipping Safety Fairways
	State Coastal Preserves
	Dredged Material Placement Sites
	State Tracts with Resource Management Codes
North Carolina	Significant Natural Heritage Areas
	Sea Turtle Sanctuary
	Crane Spawning Sanctuary
Great Lakes	IM ACC EPA
	IM Ship Routes
Virginia	Near-shore Coastal Parks
	Threatened & Endangered Species Waters
	Crab Sanctuary
	Security Areas
	Striped Bass Sanctuary
	State Park & State Dedicated Natural Area Preserve (w/in 1 mile of shoreline)
Rhode Island	Habitat Restoration Area

	Hazardous Material Sites Designated by the U.S. EPA and RIDEM (w/in 0.5 miles of shoreline)
	CRMCWT08 (Type = 1 or 2)
South Carolina:	Refuges
	OCRM Critical Area
New Hampshire	Conservation Focus Area
Florida	Ocean Dredged Material Disposal Sites
	Aquatic Preserve Boundaries
California	Cordell Banks Closed Areas
Massachusetts	Ferry Routes
Oregon	Oregon Islands National Wildlife Refuges USFWS 2004
	Oregon Marine Managed Areas
	Oregon Cables OFCC 2005
	Dredged Material Disposal Sites ACDE 2008
New Jersey	New Jersey Coastal Wind Turbine Siting Map – Exclusion Areas

[a] Exclusions were developed by Black & Veatch (2009).

Table A-9. Exclusions and Constraints for Enhanced Geothermal Systems[a]

Land Type(s) Exclusion	National Park Service Lands
	Fish and Wildlife Service Lands
	Federal Parks
	Federal Wilderness
	Federal National Monuments
	Federal National Battlefields
	Federal Restoration Areas
	Federal National Conservation Areas
	Federal Wildlife Refuge Areas
	Federal Wild and Scenic Areas

a USGS (2005)

Table A-10. Power Densities for Enhanced Geothermal Systems[a]

Temperature C	MW / km^2
150–200	0.59
200–250	0.76
250–300	0.86
300–350	0.97
> 350	1.19

[a] Augustine (2011)

Table A-11. Exclusions and Constraints for Enhanced Geothermal Systems[a]

Depth Constraints	Depth > 3 and < 10 km
Land Type(s) Exclusion	National Park Service Lands
	Fish and Wildlife Service Lands
	Federal Parks
	Federal Wilderness
	Federal National Monuments
	Federal National Battlefields
	Federal Restoration Areas
	Federal Conservation Areas
	Federal Wildlife Refuge Areas
	Federal Wild and Scenic Areas

[a] USGS (2005)

Appendix B. Energy Consumption by State

Electric retail sales in the United States were roughly 3,754 TWh in 2010 (EIA).

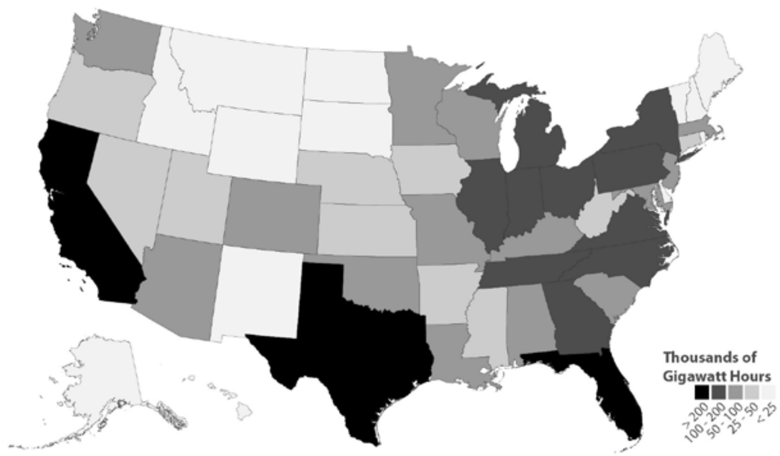

Figure B-1. Electric retail sales in the United States in 2010 (EIA).

Table B-1. Electric Retail Sales by State, 2010[a]

State	GWh		State	GWh
Alabama	90,863		Montana	13,423
Alaska	6,247		Nebraska	29,849
Arizona	72,832		Nevada	33,773
Arkansas	48,194		New Hampshire	10,890
California	258,525		New Jersey	79,179
Colorado	52,918		New Mexico	22,428
Connecticut	30,392		New York	144,624
Delaware	11,606		North Carolina	136,415
District of Columbia	11,877		North Dakota	12,956
Florida	231,210		Ohio	154,145
Georgia	140,672		Oklahoma	57,846
Hawaii	10,017		Oregon	46,026
Idaho	22,798		Pennsylvania	148,964
Illinois	144,761		Rhode Island	7,799
Indiana	105,994		South Carolina	82,479
Iowa	45,445		South Dakota	11,356
Kansas	40,421		Tennessee	103,522
Kentucky	93,569		Texas	358,458
Louisiana	85,080		Utah	28,044
Maine	11,532		Vermont	5,595
Maryland	65,335		Virginia	113,806
Massachusetts	57,123		Washington	90,380
Michigan	103,649		West Virginia	32,032
Minnesota	67,800		Wisconsin	68,752
Mississippi	49,687		Wyoming	17,113
Missouri	86,085		**U.S. Total**	**3,754,486**

[a] EIA

EPRI ELECTRIC POWER RESEARCH INSTITUTE

2014 TECHNICAL REPORT

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Product Description

This report documents the results of an exhaustive study to assess the potential for electricity energy savings and peak demand reduction from energy efficiency programs in the United States through 2035. EPRI has undertaken this study in order to inform utilities and policy makers about the ability to achieve energy efficiency in a realistic and cost effective manner. The "achievable potential" represents an estimate of savings attainable through actions that encourage adoption of energy-efficient technologies, taking into consideration technical, economic, and market constraints.

Background

EPRI first conducted an assessment of energy efficiency potential in 2009. That report "*2009 Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.*" provided a useful blueprint for program design that has guided utilities and policy makers in their design and implementation of efficiency programs since. Subsequently, the advance of efficient technologies, reductions in technology costs, economic uncertainty and the creation of minimum efficiency levels through codes and standards have created the need to update these results. This study expands these results to:

- Reflect changes in market conditions as well as changes in efficiency measures, both in terms of impacts and costs.
- Incorporate the latest, known federal codes and standards into the analysis.
- Capture future technologies and alternative stakeholder economic perspectives.
- Capture changing economics in real-time over the course of the planning horizon.

Objectives

The study's objective is to provide an independent, technically grounded estimate of the potential for electricity energy savings and peak demand reduction from energy efficiency programs through 2035 that can help inform decisions of both policy makers and electric utilities. The study forecasts the adoption of currently available energy-efficient technologies through utility- or state-agency-sponsored programs, taking into consideration technical, economic, and market constraints. This analysis was informed by observations of actual program experiences, results, and best practices.

Approach

A bottom-up methodology was applied, based on equipment stock turnover and adoption of energy efficiency measures at the technology and end-use levels for the U.S. Census divisions, as well as Florida, Texas, and California separately. This approach is grounded in actual technology efficiencies and costs gathered by technology experts at EPRI as well as observations from industry experts concerning best practices in program design. This approach is consistent with most potential studies conducted for utilities or states, but is unique in its application to the United States as a whole, yielding detailed, granular results by division, sector, building type, end-use, and technology.

Results

In its 2012 Annual Energy Outlook, the Energy Information Administration projects that electricity consumption in the U.S. residential, commercial, and industrial sectors will grow at an annual rate of 0.7% from 2012 through 2035. This is a nearly 40% reduction in the rate of growth forecast in EPRI's first potential analysis. Despite this reduction in growth and the creation of minimum efficiency standards that have the effect of reducing efficiency potential this report suggests that there continues to be an ample supply of cost effective energy efficiency for utilities to tap into. Through 2035 this report forecasts that achievable energy efficiency may result in a reduction of consumption by 11%. All sectors – residential commercial and industrial, contribute to this gain. The residential potential is forecast at a 3% percent reduction of usage by 2035, commercial 14% by 2035 and industrial 6% by 2035. Commercial lighting is forecast to provide the greatest impacts but residential space cooling, industrial facilities (HVAC and lighting) and commercial air conditioning are also expected to produce significant impacts.

Applications, Value, and Use

This study is intended to inform utilities, policymakers, regulators, and other stakeholder groups. States and utilities can compare the results of their own potential assessments to the study's divisional results. Utilities can examine the major areas of energy efficiency potential specific to their region with their own allocation of resources and consider the following questions: How many resources are we allocating to savings in this area? What programs do we have addressing this market? What results have been achieved? What state or local codes and standards exist for this market beyond federal levels?

Keywords

Energy Efficiency Potential
Market Barriers
Utility Economic Perspectives
Codes and Standards
Demand-Side Management (DSM)

Executive Summary

Electricity plays an integral role in supporting the standard of living to which Americans have grown accustom, enabling comfort, convenience, health and safety, security, and productivity in its traditional end-use applications, including air conditioning, lighting, refrigeration, and motive power. Moreover, the computational and communications infrastructure associated with our digital economy depends on electricity – from powering data centers to charging ever-proliferating mobile electronic devices.

Understanding growth in demand is key for electric service providers at all levels as they plan resources to meet customers' needs while maintaining reliable operation of the power system. The challenge to provide affordable, reliable and environmentally responsible electricity encourages providers to understand all resources available to continue to meet demand. Utilities and policy makers continue to look to energy efficiency as a cost-effective resource to enable reliable and affordable electric service while at the same time reducing carbon emissions.

In 2009 the Electric Power Research Institute commissioned a study to assess the potential energy savings achievable through energy efficiency and demand response programs in the U.S. from 2010 through 2030.[1] This study updates the 2009 assessment with several modifications to the modeling engine, treatment of end-uses, and an enhancement to reflect the U.S. Energy Information Administration's 2012 Annual Energy Outlook (*AEO2012)* baseline. A key objective of the study is to inform utilities, electric system operators and planners, policymakers, and other electricity sector industry stakeholders in their efforts to develop actionable savings estimates for end-use energy efficiency programs. The majority of the effort focused on the identification of cost-effective energy efficiency and assessment of the impacts of application of cost-effective efficiency measures beginning in 2013 through 2035. In addition to savings from energy efficiency programs, this report presents high-level impacts from the substitution of highly efficient electric technologies for fossil fueled end-uses to provide for a holistic view of the combined impact of energy-efficient electrification.

[1] *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.: (2010-2030).* EPRI, Palo Alto, CA: 2009. 1016987.

Key Findings

Electricity Consumption

According to the *AEO2012* Reference case baseline forecast, U.S. electricity consumption in 2012 of 3,722 TWh is projected to increase to 4,393 TWh in 2035, for an average annual growth of 0.72% per year. This outlook is significantly lower load growth than was evidenced over the past 30 years of 1.9% annual load growth. The *AEO2012* Reference case is predicated on a relatively flat electricity price forecast in real dollars between 2012 and 2035, suggesting slow growth in demand in the electric sector. Despite this lower load growth outlook, this study shows that energy efficiency remains a significant resource.

The *AEO2012* Reference case includes the impacts of market-driven efficiency improvements such as ENERGY STAR® labeling, the impacts of all currently legislated federal appliance standards and building codes (including the Energy Independence and Security Act of 2007) and rulemaking procedures such as California's Title 20.

The *AEO2012* also assumes continued contributions of existing utility- and government- sponsored energy efficiency programs established prior to 2012. The savings impact of energy efficiency programs "embedded" in the *AEO2012* Reference case is estimated in Section 2 of the report. Removing this estimate of embedded savings from the *AEO2012* Reference case results in an adjusted baseline forecast that is higher; this adjusted baseline is used throughout this report.

EPRI estimates that energy efficiency programs have the potential to reduce electricity consumption in 2035 by 488 to 630 billion kWh. This represents a range of achievable potential reduction in electricity consumption in 2035 – from a "moderate case" or *achievable potential* of 11% to a "high case" or *high achievable potential* of 14%.[2,3] Relative to the *AEO2012* Reference case, which implicitly assumes some level of energy efficiency program impact, this study identifies between 352 and 494 billion kWh of *additional cost-effective savings potential* from energy efficiency programs.

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[2] The values for achievable and high achievable potentials in 2035 measured with respect to the baseline forecast described in footnote 3 (and detailed in Section 2) are 488 and 630 billion kWh, respectively, or 11 to 14%. These values represent the total savings impact of cost-effective energy efficiency programs in 2035 inclusive of savings embedded in the *AEO2012* Reference case.

[3] Achievable potential (AP) can be thought of as a "moderate case" for the savings impact of energy efficiency programs; high achievable potential (HAP) can be thought of as a "high case" for the savings impact of energy efficiency programs. Though the terms may be used interchangeably, the nomenclature of AP and HAP are used throughout this report.

Therefore, energy efficiency programs have the potential to reduce the 0.72% annual *growth rate* in electricity consumption forecasted in the *AEO2012* Reference case between 2012 and 2035 by 51% to 72%, to an annual growth rate of 0.36% to 0.20%.

These estimated levels of electricity savings are achievable through voluntary energy efficiency programs implemented by utilities or similar entities. Our analysis does not assume the enactment of new energy codes and efficiency standards beyond what is already in law. More progressive codes and standards would yield even greater levels of electricity savings.

Peak Demand

Summer coincident peak demand in the U.S., is projected to be 595 GW in 2012, and is expected to increase to 714 GW by 2035, reflecting 0.8% compound annual growth.

Energy efficiency programs have the potential to reduce coincident summer peak demand by 79 to 117 GW. This represents a range of achievable potential reduction in 2035 summer peak demand of 11% to 16%. This can also be expressed as a 65% to 98% reduction in the forecasted *annual growth rate* of summer peak demand through 2035.

Winter coincident peak demand in the U.S., is projected to be 495 GW in 2012, and is expected to increase to 628 GW by 2035, reflecting 1.03% compound annual growth. Winter peak demand is expected to grow at a faster annual rate than electricity use due partly to the expected growth in the share of electric water heating.

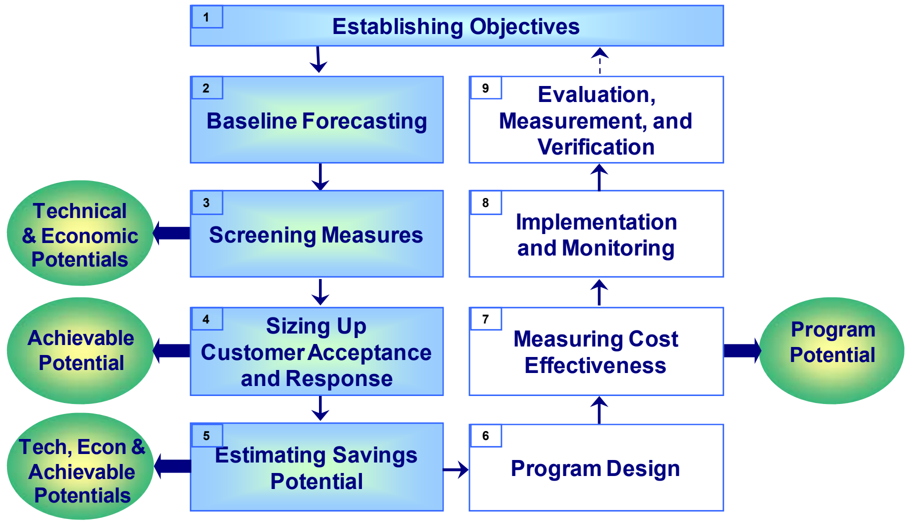
Energy efficiency programs have the potential to reduce coincident winter peak demand by 64 to 89 GW. This represents a range of achievable potential reduction in winter peak demand in 2035 of 10% to 14%. This can also be expressed as a 45% to 65% reduction in the forecasted *annual growth rate* of winter peak demand through 2035.

These estimated levels of peak demand reduction are achievable through voluntary energy efficiency programs implemented by utilities or similar entities. Our analysis does not assume the enactment of new energy codes and efficiency standards beyond what is already in law. More progressive codes and standards would yield even greater levels of peak demand reduction.

Analysis Approach

This study implemented an analysis approach consistent with the methods described in EPRI's Energy Efficiency Planning

Guidebook,[4] (as depicted in steps 1 through 5 of Figure 1), and the National Action Plan for Energy Efficiency (NAPEE) Guide for Conducting Energy Efficiency Potential Studies[5].



Source: Energy Efficiency Planning Guidebook, EPRI 1016273, June 2008

Figure 1
General Energy Efficiency Analysis Framework

Defining Potential

The primary focus of this study was to develop a range of energy efficiency potentials. The approach for deriving *achievable potential* is predicated on first establishing the theoretical constructs of *technical potential* and *economic potential* and then discounting them to reflect market and institutional constraints. This study applies the condition that new equipment does not replace existing equipment instantaneously or prematurely, but rather is "phased-in" over time as existing equipment reaches the end of its useful life.

[4] *Energy Efficiency Planning Guidebook.* EPRI, Palo Alto, CA: 2008. 1016273.

[5] P. Mosenthal and J. Loiter, "Guide for Conducting Energy Efficiency Potential Studies," U.S. EPA, Arlington, VA, 2007.

All categories of potentials in this study conform to this condition, and may be termed "phase-in" potentials.[6] The categories of potential employed in this study are described in the following.

Technical Potential

The technical potential represents the savings due to energy efficiency and programs that would result if all homes and businesses adopted the most efficient, commercially available technologies and measures, *regardless of cost*. Replacement is assumed to occur at the end of their useful lives by the most efficient option available. Technical potential does not take into account the cost-effectiveness of the measures, or any market barriers.

Economic Potential

The economic potential represents the savings due to programs that would result if all homes and businesses adopted the most energy-efficient cost-effective commercially available measures. With the efficiency measure inputs and avoided costs, the Total Resource Cost test (TRC) benefit-cost ratio is calculated over the life of the measure. The ratio compares the present worth of the avoided power supply costs to the incremental measure cost plus the energy efficiency program administration cost.

Economic potential does not take into account market barriers to adoption. Within a measure category, if several measures pass with a benefit-cost ratio greater than or equal to 1.0, the most efficient measure (greatest energy savings) is adopted.

The initial modeling outputs are a set of electricity and peak demand reduction values under the technical and economic potential cases. As described above, these potentials are the result of assumptions about the adoption of efficiency measures, whether through a stock accounting framework, a device saturation approach, or the application of savings values to the pertinent segments of the baseline. The next step is to obtain the achievable potentials through the introduction of market acceptance ratios and program implementation factors, which reflect known barriers to demand-side activities.

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[6] For the purposes of this study, no "mid-life" replacements of existing equipment for more efficient equipment are assumed, even though in some instances such replacements may be economically justifiable. Consumers or firms that initiate such replacements could be considered predisposed to efficiency or conservation, and their actions may be grouped in the category or market-driven or "naturally-occurring" savings if they would occur independent of an energy efficiency program.

High Achievable Potential

The high achievable potential (HAP) takes into account those barriers that limit customer participation. These barriers can include perceived or real quality differences, aesthetics, customer inertia, or customer preferences for product attributes other than energy efficiency. HAP is estimated by applying market acceptance ratios (MARs) to the economic potential savings from each measure in each year.

MARs capture the effects of market barriers which at a high level include transactional, informational, behavioral, and financial barriers. They are essentially scaling factors applied to the measure savings over time, and are defined in ten-year intervals and change over time (maximum of 100%) to reflect that market barriers are likely to decrease over time. MARs can also be thought of as representing what exemplary energy efficiency programs have achieved, assuming that they have overcome market barriers to some extent.

Achievable Potential

Unlike the other potential estimates, the achievable potential (AP) represents a forecast of likely consumer adoption. It takes into account existing market delivery, financial, political and regulatory barriers that are likely to limit the amount of savings that might be achieved through energy-efficiency programs. For example, utilities do not have unlimited budgets for program implementation. There can be regional differences in attitudes toward energy efficiency and its value as a resource. AP is calculated by applying a program implementation factor (PIF) to the HAP for each measure. The program implementation factors were developed by taking into account recent utility experience with such programs and their reported savings. These factors also change over time to reflect that programs may be able to achieve increased savings as programs mature.

The Starting Point: Base-Year Electricity Use by Sector and End Use

Based on the *AEO2012* baseline, annual electricity use for the U.S. is estimated at 3,724 TWh. This represents 11.8 MWh per capita and 0.28 kWh per dollar of Gross Domestic Product in 2012. The allocation of U.S. electricity use across sectors is fairly even, where the residential sector accounts for 38%, the commercial sector accounts for 36%, and the industrial sector uses 26%.

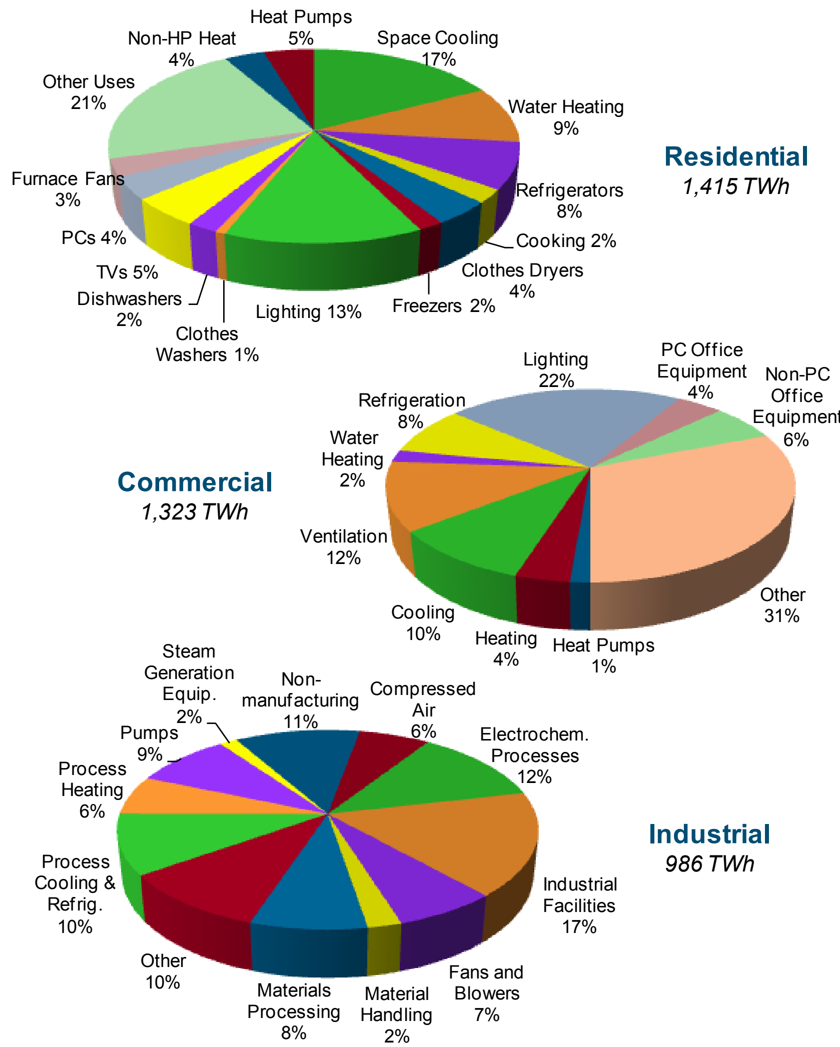

Figure 2
2012 U.S. Electricity Consumption by Sector and End Use[7]

Overall, other uses accounts for 22% of consumption across all three sectors. Lighting and heating, air conditioning and ventilation (HVAC) are major categories in both residential and commercial. This is the top end-use category in industrial, grouped under "industrial facilities" which includes HVAC, lighting and other non-process consumption. The complete breakout of 2012 consumption in each sector by end use is shown in Figure 2.

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[7] These values represent the total electricity consumption in 2012 inclusive of savings embedded in the *AEO2012* Reference case.

The Baseline Forecast

Our nation's usage of electricity to power homes, buildings, industrial facilities and public areas is expected to increase by 18% between 2012 and 2035, according to the *AEO2012* Reference case baseline.[8] The projected annual growth rate for the residential, commercial and industrial sectors is forecast to be 0.72% between 2012 and 2035, as illustrated in Figure 3. Although steady growth is predicted, the AEO forecast of growth in electricity consumption has been declining year over year accounting for shifts in the economy, energy prices, and technology innovation among other things.

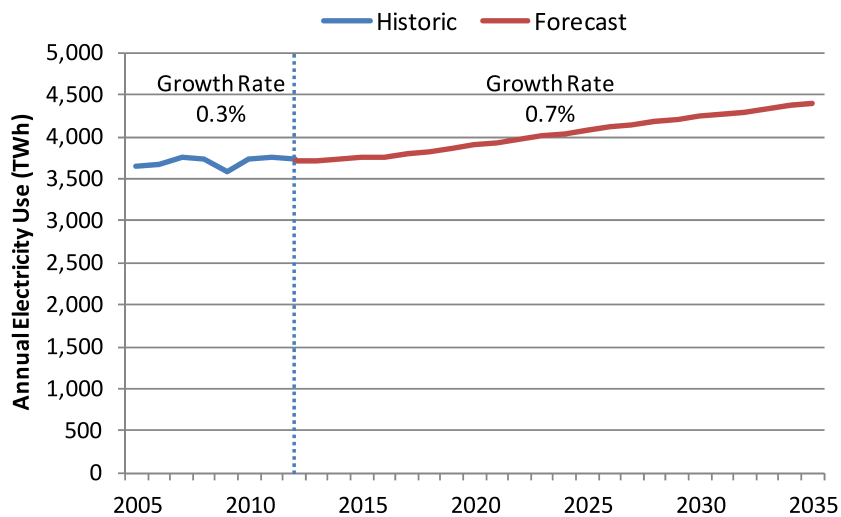


Figure 3
AEO2012 Reference Case Electricity Consumption Forecast

The macroeconomic drivers of the AEO forecast include U.S. population, employment, Gross Domestic Product (GDP), value of shipments, housing starts, and building construction. Average growth in GDP between 2012 and 2035 is 2.6%, more than three times the rate of projected electricity growth. This implies a decline in the electricity intensity per GDP.

By 2035, electricity use is expected to increase to 4,393 TWh, a 18% increase over use in 2012. This Reference case forecast already includes expected savings from several efficiency drivers including:

[8] "Annual Energy Outlook 2012 with Projections to 2035," U.S. DOE EIA, Washington DC, DOE/EIA-0383(2012), June 2012. http://www.eia.gov/forecasts/aeo/pdf/0383%282012%29.pdf

- Codes and Standards
  - Federal, state, and local building efficiency codes already enacted
  - Appliance and equipment standards already enacted; this includes the Energy Independence and Security Act of 2007, which, among its features, mandates higher lighting efficiency standards
  - Other possible related effects, including structural changes in the economy that impact overall electric energy intensity
- Market-Driven Efficiency
  - Trends in customer purchases of energy-efficient equipment attributable to market-driven effects outside of utility programs
- Implicit Programs
  - An estimate of the utility-based energy efficiency programs adopted prior to 2012, and an estimate of the impact of these existing programs

Throughout the forecast period the energy consumption for newly installed equipment is reduced as new products conform to the requirements of previously legislated codes and standards. To estimate the impacts of these codes and standards in the residential and commercial sectors, the project team ran a scenario in which the energy consumption of new products was frozen at 2012 levels throughout the forecast horizon. In the residential sector the end-use unit energy consumption (UEC) in kWh per year was held constant; and in the commercial sector the energy use intensity (EUI) in kWh per square foot was held constant. The difference between newly installed stock with 2012 energy consumption vs. evolving consumption over time reflects the impact of current codes and standards in the residential and commercial baselines. This case of the electricity forecast "but for the impact of existing codes and standards" is depicted as the top line in Figure 4.

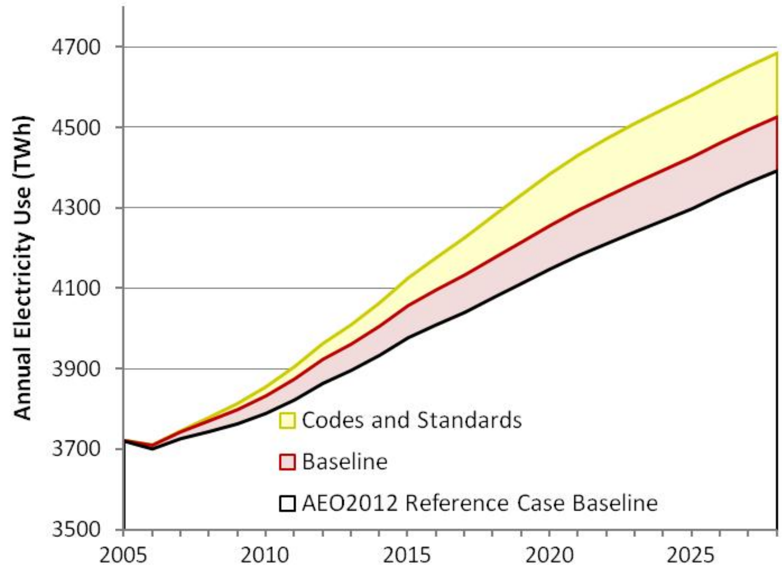


Figure 4
Estimated Impact of Energy Efficiency Drivers Inherent in AEO2012 Reference Case

The estimated impact of energy efficiency programs "embedded" in the *AEO2012* Reference case was "added back" to construct an adjusted "baseline" forecast, in accordance with standard industry practice. This baseline represents a projection of electricity consumption absent of any assumed impact of energy efficiency programs.

The baseline forecast does not assume any expected savings from future federal or state appliance and equipment standards or building codes not currently enacted. Finally, the baseline embodies the *AEO2012* price forecast, which is relatively flat in real terms over the forecast horizon.

The Potential for Electricity Savings from Utility Programs

The analysis of potential savings from utility programs began with a list of energy efficiency measures. This list includes high-efficiency appliances and equipment for most end uses, many of which have numerous efficiency levels, devices, controls, maintenance actions, and enabling technologies such as programmable thermostats. Table 1 summarizes the residential and commercial energy-efficiency measure categoriess included in the analysis.

No measures are applied per se in the industrial sector. Instead, the savings are applied top-down to process-level consumption within each manufacturing segment.

Table 1
Summary of Residential and Commercial Efficiency Measure Categories

Residential Sector Measure Categories
Efficient air conditioning (central, room)
Efficient space heating and cooling (heat pumps)
Efficient water heating (e.g. heat pump water heaters & solar water heating)
Efficient appliances (refrigerators, freezers, washers, dryers)
Efficient lighting (CFL, LED, linear fluorescent)
Efficient power supplies for Information Technology and consumer electronic appliances
Air conditioning and heat pump maintenance
Duct repair and insulation
Infiltration control
Whole-house and ceiling fans
Reflective roof, storm doors, external shades
Roof, wall and foundation insulation
High-efficiency windows
Faucet aerators and low-flow showerheads
Pipe insulation
Programmable thermostats
In-home energy displays
Commercial Sector Measure Categories
Efficient cooling equipment (chillers, central AC)
Efficient space heating and cooling equipment (heat pumps)
Efficient water heating equipment
Efficient refrigeration equipment & controls
Efficient lighting (interior and exterior)
Efficient power supplies for Information Technology and electronic office equipment
Water temperature reset
Efficient air handling and pumps
Economizers and energy management systems (EMS)
Programmable thermostats
Duct insulation

As described above, the full set of measures is included in the estimation of technical potential, while only the subset that passes the economic screen is included in economic and achievable potentials.

Table 2 presents energy-efficiency potential estimates for the U.S. in 2025 and 2035. Relative to the baseline forecast, in 2035:

- Achievable Potential is 488 TWh, or an 11% reduction in projected consumption
- High Achievable Potential is 630 TWh, or an 14% reduction in projected consumption

Relative to the *AEO2012* Reference case, in 2035:

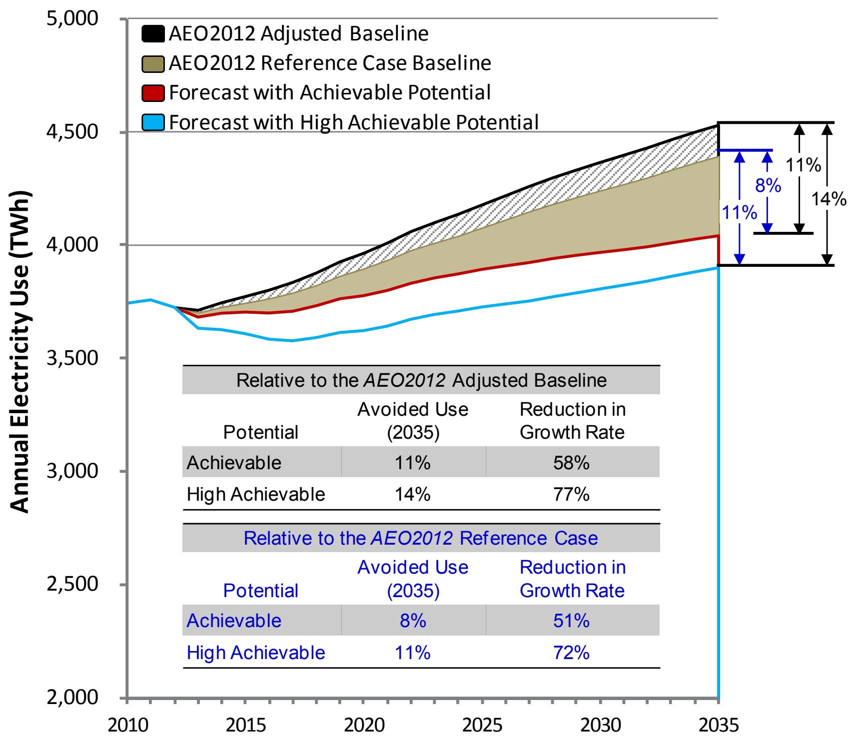
- Achievable Potential represents 352 TWh of *additional* energy efficiency savings, or a 8% reduction in projected consumption.
- High Achievable Potential represents 494 TWh of *additional* energy efficiency savings, or an 11% reduction in projected consumption.

These estimates suggest that energy efficiency programs can realistically reduce the annual growth rate of U.S. electricity consumption from 2012 to 2035 projected by the *AEO2012* Reference case by 51%, from 0.72% to 0.36%.

Table 2
Energy Efficiency Potential for the U.S.

	***AEO2012* Reference Case**	**Baseline Forecast**	**Achievable Potential**	**High Achievable Potential**
Forecasts (TWh)				
2025	4,078	4,177	3,893	3,725
2035	4,393	4,529	4,041	3,898
Savings Relative to *AEO2012* Reference Case (TWh)				
2025	-	-	185	352
2035	-	-	352	494
Savings Relative to Baseline Forecast (TWh)				
2025	-	-	284	451
2035	-	-	488	630

Figure 5 illustrates this achievable savings potential.



Relative to the *AEO2012* Adjusted Baseline		
Potential	Avoided Use (2035)	Reduction in Growth Rate
Achievable	11%	58%
High Achievable	14%	77%

Relative to the *AEO2012* Reference Case		
Potential	Avoided Use (2035)	Reduction in Growth Rate
Achievable	8%	51%
High Achievable	11%	72%

Figure 5
U.S. Energy Efficiency Achievable Potential

Although there are savings in a wide range of end uses in the residential, commercial and industrial sectors, Figure 6 presents the highest saving end uses in each of the sectors. Commercial indoor lighting presents significant opportunities for energy savings, more than the sum of the remaining end uses presented in Figure 6, and 38% of the total achievable 2035 energy savings. Lighting opportunities are also captured under the heading of industrial facilities which includes HVAC, water heating and lighting for the industrial sector.

Space cooling is in the top three for both residential and commercial where more efficient central air conditioners, room air conditioners and chillers present cost-effective energy savings above and beyond what is mandated by codes and standards.

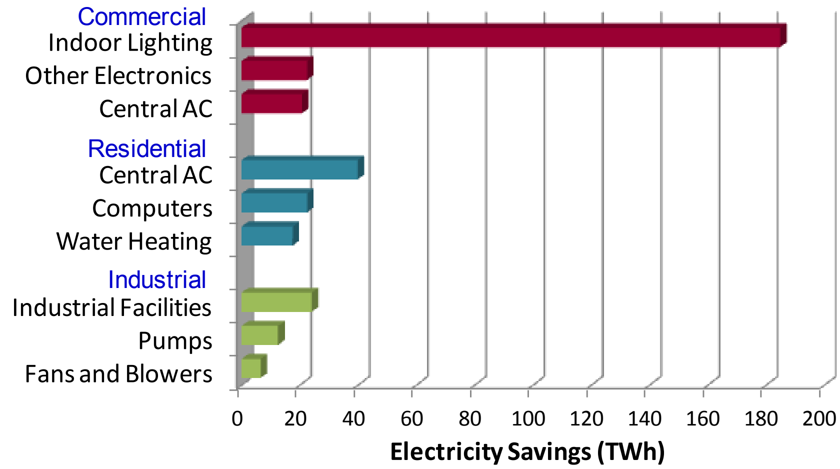


Figure 6
Top Three End Uses for Achievable Energy Savings, 2035

Water heating also presents the opportunity for significant savings in the residential sector for smaller units, with capacity less than 55 gallons.

The remaining heavy hitters have several common threads that will provide new opportunities for energy savings beyond what we expect to see today:

- Advanced motor technologies,
- New materials in batteries and electronics, and
- Advanced power management.

Figure 7 displays the individual measures with the highest potential for savings across all the sectors.

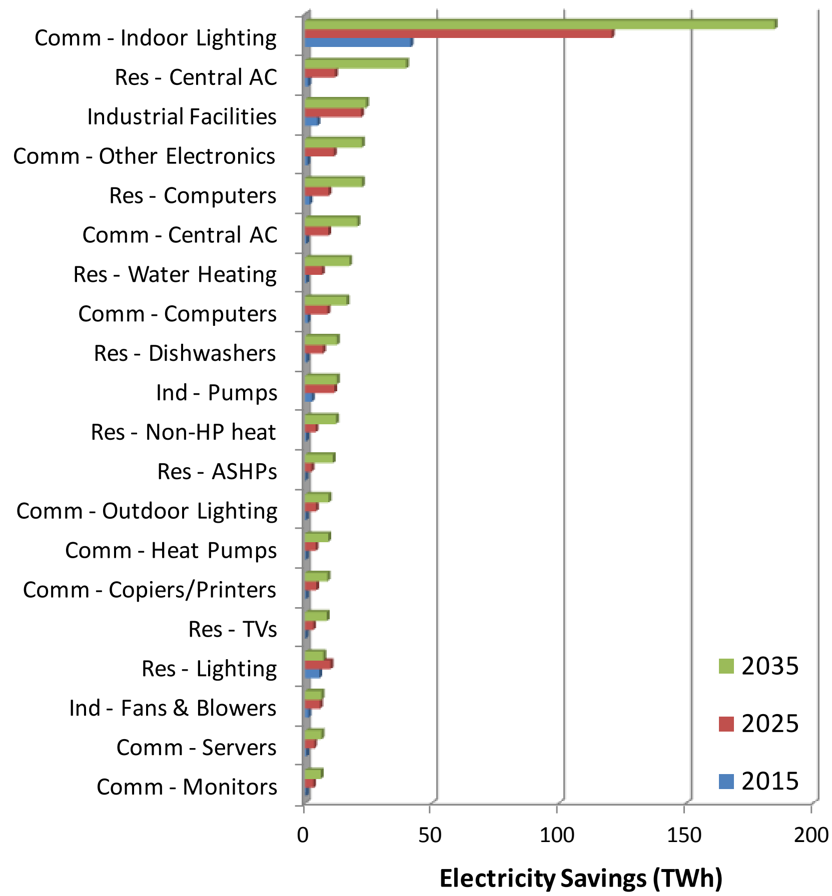


Figure 7
Top Twenty End Uses for Achievable Energy Savings, 2035

Energy Efficiency Savings Potential by U.S. Census Region

This study disaggregates electricity baseline consumption and potential energy efficiency savings by the ten U.S. Census divisions plus three large states (Florida, Texas and California) shown in Figure 8.

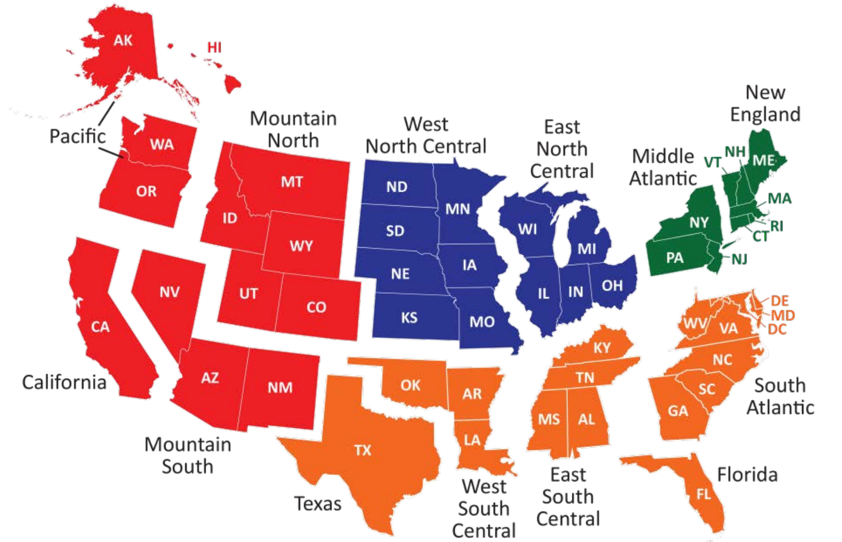


Figure 8
Geographic Divisions – Ten Census Divisions plus Three States

Figure 9 illustrates how the total U.S. 2035 achievable potential is broken out among the divisions.

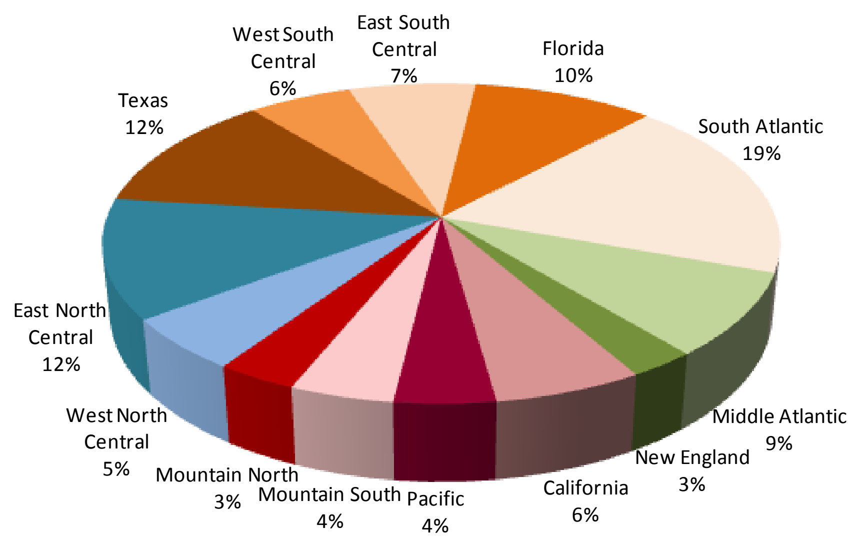


Figure 9
Division Shares of 2035 Achievable Potential

Key takeaways for achievable potential in the regions include:

- Electricity consumption is highest in the South, and is expected to grow at an annual rate of 1.1% through 2035. The South is also the region with the greatest potential for energy efficiency in absolute terms.
- Electricity consumption is lowest in the Northeast, with the smallest expected to growth rate of 0.2% through 2035. The Northeast's energy efficiency potential is the smallest of the four regions, although by share of total load it ranks third.
- The Midwest is the second largest region in terms of both current and forecasted growth, with an annual growth rate of 0.4%.
- Finally, the West is the region of most rapid forecasted growth at 1.2% per year, and has the third largest potential for energy efficiency in percentage terms.

Table 3 shows the absolute values for 2035 achievable potential by division and broken out by sector. In all cases the potential for savings is greatest in the commercial sector with indoor lighting providing top savings across the board.

Table 3
2035 Achievable Potential by Division and Sector

	Res.	Comm.	Ind.	Total
Northeast Census Region				
New England	2,795	9,359	1,321	13,475
Middle Atlantic	7,383	30,620	3,090	41,093
South Census Region				
South Atlantic	29,666	54,312	5,912	89,889
Florida	19,432	27,089	2,946	49,468
E. South Central	11,749	15,282	7,639	34,670
W. South Central	9,326	15,424	3,442	28,192
Texas	22,840	29,857	6,663	59,360
Midwest Census Region				
E. North Central	8,625	40,488	9,602	58,715
W. North Central	7,204	14,611	4,232	26,047
West Census Region				
Mountain North	3,664	10,258	2,235	16,158
Mountain South	6,016	12,180	2,654	20,850
Pacific	3,772	14,024	2,399	20,195
California	6,035	20,315	3,475	29,826

Figure 10 illustrates how the savings in each sector compares to the division's baseline consumption. Although the absolute savings vary among divisions, the savings as a percentage of the division's baseline range from 8% to 14%. In all but one Southern division the savings are the highest across all divisions, while in the Midwest divisions (East North Central and West North Central) the savings are below 10% of the baseline.

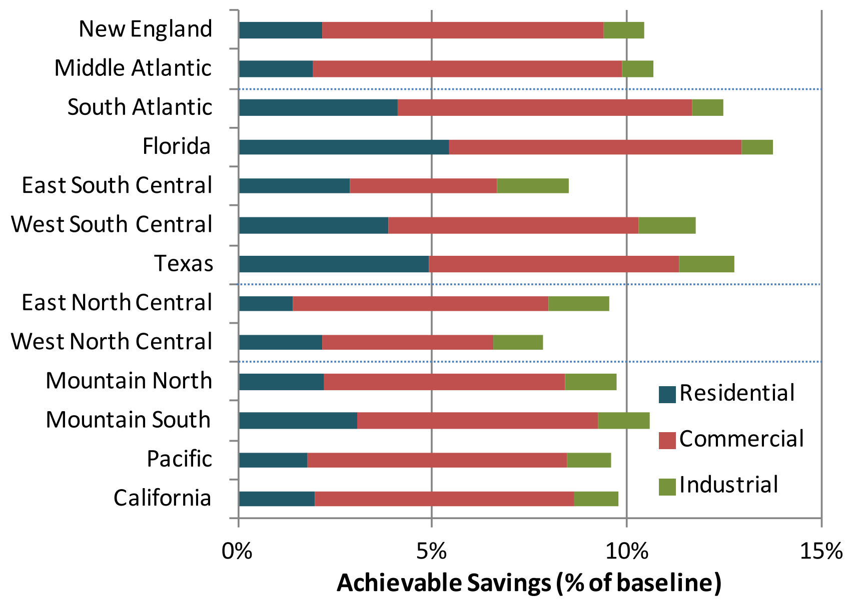


Figure 10
2035 Division-Level Achievable Potential as a Percentage of Division Baseline

Tables 4 through 7 lend some insight into the differences between savings among the divisions. Commercial indoor lighting is top in all divisions, the other top saving end uses lend some insight into variations in end-use consumption amongst the divisions.

Table 4 shows the top three end uses for 2035 achievable potential for the Northeast divisions. Electronics, both miscellaneous electronics for commercial or residential computers present relatively high opportunities for savings compared to other end uses. It would be useful to better understand trends in electronics in the Northeast in the future to best understand how the potential for savings will change over time.

Table 4
Top Three End Uses for 2035 Achievable Potential, Northeast Census Region

Division	End Use	Savings (GWh)	% of Baseline
New England	Comm - Indoor Lighting	6,680	5.2%
	Res - Computers	882	0.7%
	Comm - Other Electronics	742	0.6%
Middle Atlantic	Comm - Indoor Lighting	20,842	5.4%
	Comm - Other Electronics	2,729	0.7%
	Res - Computers	2,436	0.6%

Notes: New England includes NH, VT, ME, MA, RI, and CT. Middle Atlantic includes NY, NJ, and PA.

The top three end uses in the South are shown in Table 5. Central air conditioning both in the residential and commercial sectors make it into the top three in almost all cases. This points to the increased consumption for space cooling in the South. Industrial facilities also makes the top three in the East South Central and presents the largest opportunity for savings in the industrial sector.

Table 5
Top Three End Uses for 2035 Achievable Potential, South Census Region

Division	End Use	Savings (GWh)	% of Baseline
South Atlantic	Comm - Indoor Lighting	31,595	4.4%
	Res - Central AC	9,198	1.3%
	Comm - Central AC	7,154	1.0%
Florida	Comm - Indoor Lighting	15,746	4.4%
	Res - Central AC	6,735	1.9%
	Comm - Central AC	3,567	1.0%
East South Central	Comm - Indoor Lighting	10,367	2.5%
	Industrial Facilities	3,233	0.8%
	Res - Central AC	3,211	0.8%
West South Central	Comm - Indoor Lighting	8,228	3.4%
	Res - Central AC	3,310	1.4%
	Comm - Central AC	3,036	1.3%
Texas	Comm - Indoor Lighting	15,929	3.4%
	Res - Central AC	11,253	2.4%
	Comm - Central AC	5,873	1.3%

Notes: South Atlantic includes WV, VA, DE, MD, DC, NC, SC, and GA. East South Central includes KY, TN, MS, and AL. West South Central includes OK, AR, and LA.

Table 6 presents the top three for the Midwest. Industrial facilities is in the top three for both divisions, which includes industrial HVAC and lighting. Otherwise no heating or cooling makes it into the top three in the Midwest where there is less electric space heating and cooling than in other divisions.

Table 6
Top Three End Uses for 2035 Achievable Potential, Midwest Census Region

Division	End Use	Savings (GWh)	% of Baseline
East North Central	Comm - Indoor Lighting	28,222	4.6%
	Industrial Facilities	4,043	0.7%
	Comm - Other Electronics	3,681	0.6%
West North Central	Comm - Indoor Lighting	10,367	3.1%
	Industrial Facilities	1,782	0.5%
	Residential Computers	1,544	0.5%

Notes: East North Central includes WI, MI, IL, IN, and OH. West North Central includes ND, SD, MN, NE, IA, KS, and MO.

Table 7 shows mixed results for the West with electronics – residential computer or commercial electronics – showing up in a few of the West divisions. Mountain South has residential cooling in the top three pointing to the relatively high share of central AC consumption in the baseline.

Table 7
Top Three End Uses for 2035 Achievable Potential, West Census Region

Division	End Use	Savings (GWh)	% of Baseline
Mountain North	Comm - Indoor Lighting	6,668	4.0%
	Industrial Facilities	1,011	0.6%
	Res - Computers	902	0.5%
Mountain South	Comm - Indoor Lighting	7,917	4.0%
	Res - Central AC	1,810	0.9%
	Industrial Facilities	1,201	0.6%
Pacific	Comm - Indoor Lighting	9,089	4.3%
	Comm - Other Electronics	1,744	0.8%
	Res - Computers	1,340	0.6%
California	Comm - Indoor Lighting	13,167	4.3%
	Comm - Other Electronics	2,526	0.8%
	Res - Computers	1,941	0.6%

Notes: ASHP = air-source heat pumps. Mountain North includes MT, ID, WY, UT, and CO. Mountain South includes AZ, NM, and NV. Pacific includes WA, OR, AK, and HI.

The Potential for Peak Demand Savings from Utility Programs

In addition to the impacts on annual electricity use, the study assessed both summer and winter coincident peak demand savings from energy efficiency.

Energy efficiency programs have the potential to reduce coincident summer peak demand by 79 GW to 635 GW. This represents a range of achievable potential reduction in summer peak demand in 2035 of 11% to 16%. This can also be expressed as a reduction in the forecasted growth rate in peak demand of 65% to 98% through 2035.

Energy efficiency programs have the potential to reduce coincident winter peak demand by 64 GW to 564 GW. This represents a range of achievable potential reduction in summer peak demand in 2035 of 10% to 14%. This can also be expressed as a reduction in the forecasted growth rate in peak demand of 45% to 65% through 2035.

Figure 11 shows the various levels of potential for summer coincident demand savings in the key forecast years, with 11.1% achievable potential in 2035 across all sectors. This illustrates how the potential builds over time as the efficient measures are installed.

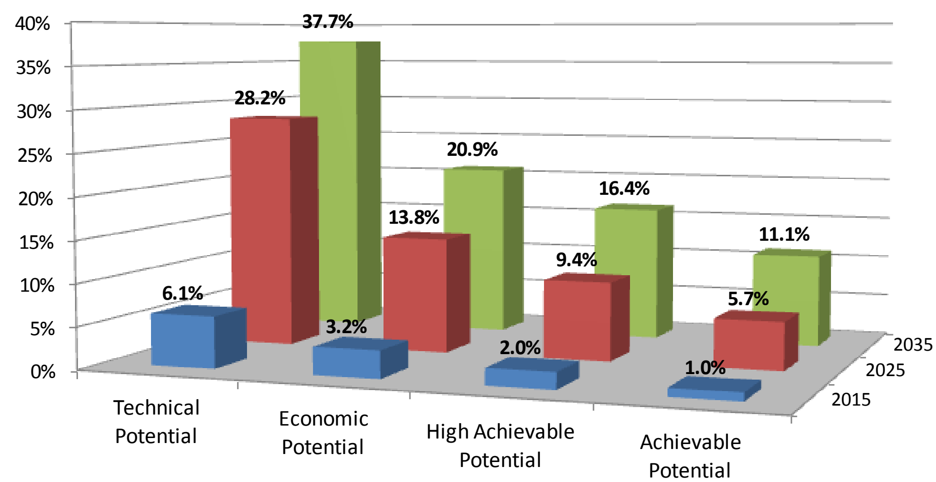


Figure 11
U.S. Summer Coincident Peak Demand Reduction

Figure 12 breaks out the achievable potential by sector as a percentage of each sector's baseline. Clearly there is great potential for savings in the commercial sector, which is in line with the energy savings results presented in Section 4.

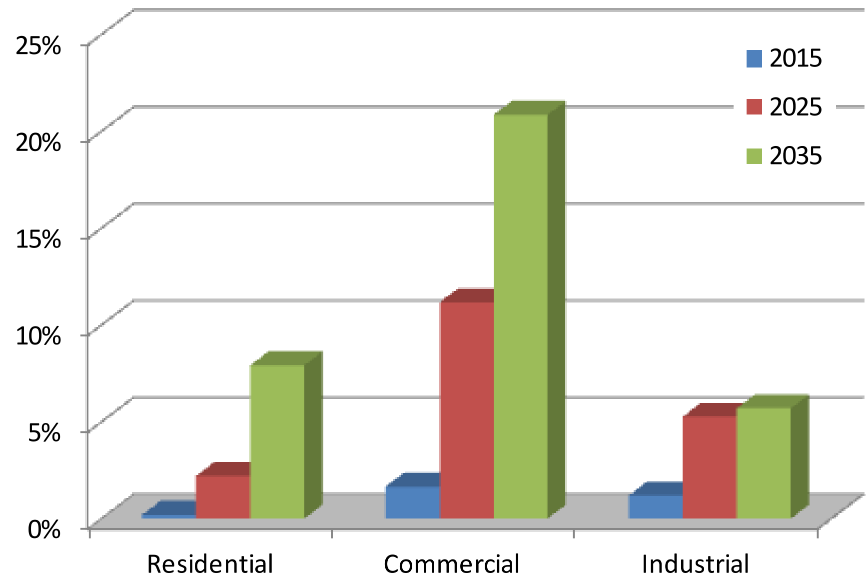


Figure 12
Summer Peak Demand Achievable Potential by Sector, as Percentage of Sector Energy Baseline

Table 8 presents summer coincident peak demand achievable savings potential by sector and end use, the achievable potential savings in 2035 across all sectors is 11.1%.

The majority of summer demand savings are in the areas of HVAC, water heating and lighting, together accounting for 69% of the 2035 savings.

Space cooling in the residential and commercial sectors accounts for about 30% of summer demand savings in 2035. Lighting accounts for another 30% of 2035 achievable potential. These do not include industrial facilities, which captures HVAC and lighting savings in the industrial sector.

Table 8
Achievable Summer Peak Demand Reductions by Sector and End Use (MW)

	2015	2025	2035
Residential			
Space Cooling	377	4,034	16,787
Electronics	145	1,532	5,689
Water Heating	73	959	2,996
Lighting	92	1,233	2,705
Appliances	48	490	1,373
Residential Total	**735**	**8,248**	**29,550**
Commercial			
Lighting	2,886	15,545	22,236
Office Equipment	304	4,391	12,867
Space Cooling	126	2,404	6,513
Ventilation	9	172	428
Water Heating	1	1	1
Refrigeration	0.0	0.0	1
Commercial Total	**3,326**	**22,512**	**42,046**
Industrial			
Industrial Facilities	718	3,172	3,429
Pumps	372	1,646	1,784
Fans and Blowers	194	861	933
Process Cooling & Refrig.	140	616	665
Process Heating	132	584	630
Compressed Air	90	398	432
Steam Generation Equipment	13	57	62
Industrial Total	**1,660**	**7,334**	**7,935**
U.S. Total	**5,721**	**38,094**	**79,531**

Note: Numbers in table may not sum to the total due to rounding.

Figure 13 shows the various levels of potential for winter coincident demand savings in the key forecast years, with 10.2% achievable potential in 2035 across all sectors. This illustrates how the potential builds over time as the efficient measures are installed.

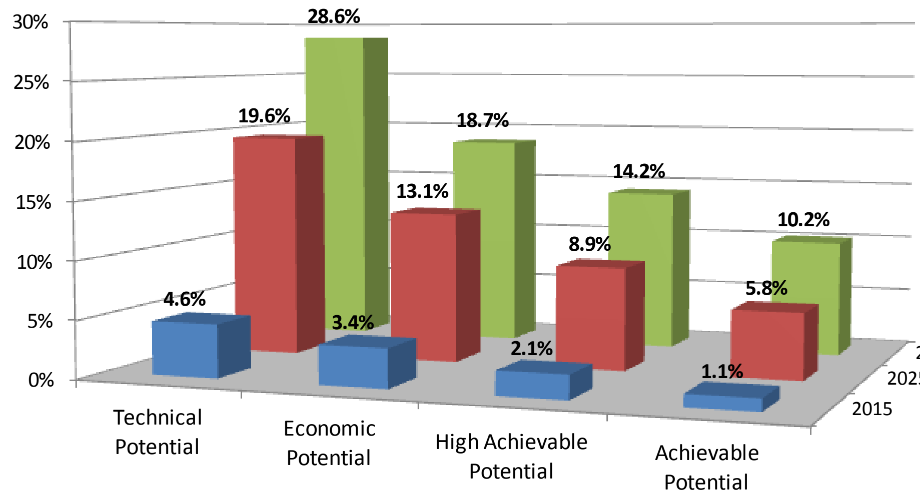


Figure 12
U.S. Summer Coincident Peak Demand Reduction

Figure 13 breaks out the achievable potential by sector as a percentage of each sector's baseline. The relatively high potential in the commercial sector, is again evident.

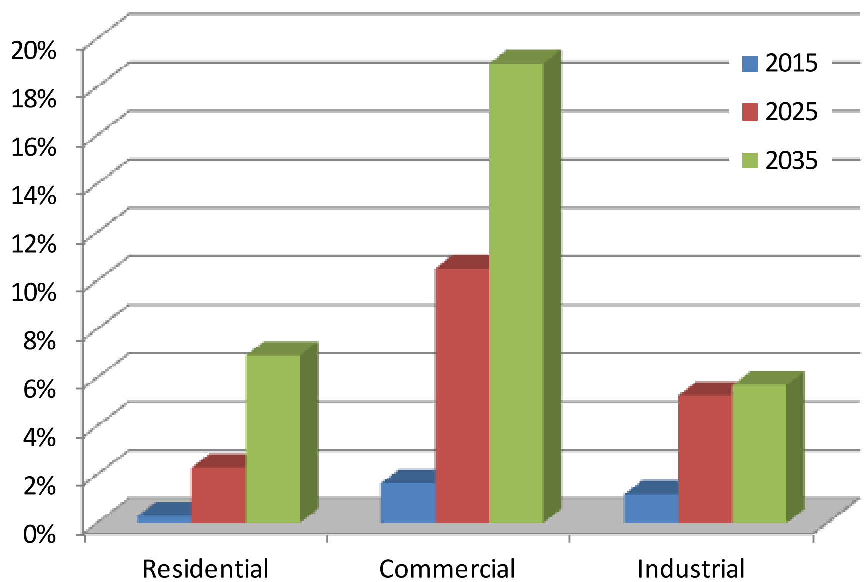


Figure 13
Winter Peak Demand Achievable Potential by Sector, as Percentage of Sector Energy Baseline

Table 9 presents winter coincident peak demand achievable savings potential by sector and end use, the achievable potential savings in 2035 across all sectors is 10.2%. The majority of winter demand savings are also in the areas of HVAC, water heating and lighting, together accounting for 62% of the 2035 savings.

Energy efficiency in heating end uses does not have quite as much impact on winter demand savings as space cooling on summer demand, accounting for about 14% of 2035 achievable potential. Lighting presents the bulk of savings potential for winter demand contributing about 40% of the total. Again, space heating and lighting savings from industrial facilities is not included in these totals due to lack of details on how it is broken out.

Table 9
Achievable Winter Peak Demand Reductions by Sector and End Use (MW)

	2015	2025	2035
Residential			
Space Heating	236	2,288	8,361
Electronics	123	1,306	4,848
Lighting	413	2,236	4,479
Water Heating	55	721	2,233
Appliances	44	453	1,252
Residential Total	**871**	**7,004**	**21,173**
Commercial			
Lighting	2,659	14,410	20,788
Office Equipment	305	4,403	12,903
Space Heating	11	157	465
Ventilation	10	176	439
Water Heating	2	3	2
Refrigeration	0.0	0.0	0.5
Commercial Total	**2,986**	**19,149**	**34,598**
Industrial			
Industrial Facilities	718	3,172	3,429
Pumps	372	1,646	1,784
Fans and Blowers	194	861	933
Process Cooling and Refrig.	140	616	665
Process Heating	132	584	630
Compressed Air	90	398	432
Steam Generation Equipment	13	57	62
Industrial Total	**1,660**	**7,334**	**7,935**
U.S. Total	**5,517**	**33,487**	**63,706**

Note: Numbers in table may not sum to the total due to rounding.

Net Impacts of Efficiency and Electrification

Forecasts for load growth vary by utility and are influenced by population growth, industrial development, economic growth and many other factors. Historically growth in electricity consumption was in the range of several percent. There are now places where this growth has fallen to less than a percent – as is the case with the national *AEO2012* forecasts – or may be expected to decline.

With this in mind we can look for opportunities beyond energy efficiency for increasing customer value and productivity and providing benefits to society as a whole. There are other prevailing trends that are likely to impact electricity consumption including new electric end uses, digitization, and emissions regulations to name a few.

The energy savings evaluated herein represent cost-effective efficiency from the point of view of the utility, which also yield net benefits to customers and society at-large. Similarly, certain applications of *electrification*, defined as the substitution of electric for non-electric end-use technologies, can also yield net benefits to customers, the utility, and society at-large. Electrification can be inclusive of the residential, commercial, and industrial sectors, as well as the transportation sector through the adoption of electric vehicles.

EPRI's previous evaluations of electrification, have focused on quantifying expected market trends and resultant impacts on net CO_2 emissions, more so than cost-effectiveness. The latter is a subject of current EPRI industry initiative.

EPRI has conducted a high-level analysis of electrification potential, as well as assessments of electric transportation market trends for both light-duty vehicles and non-road transportation. Together, these analyses provide a basis for estimating the resultant increase in electricity consumption. The results of these studies are presented along with the achievable energy savings form energy efficiency in Figure 14.

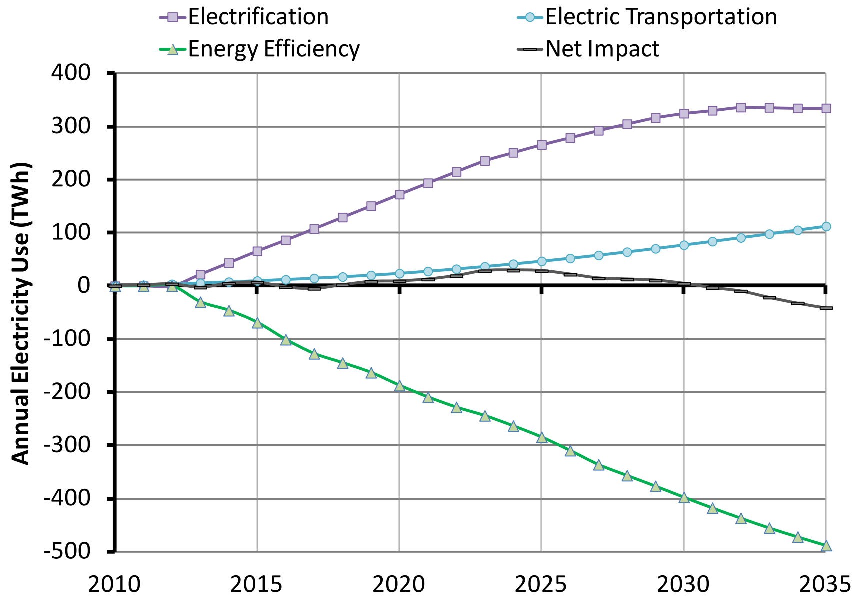


Figure 14
Net Impacts of Electrification and Energy Efficiency

Preliminary analysis of these three trends show that the savings achieved with energy efficiency could net the effects of increased electricity consumption through electrification. With respect to carbon emissions, reductions can be achieved through both electric efficiency and electrification. This presents expanded opportunities for utilities to increase value and productivity with one or more of these activities with a net result that could increase or decrease their forecast growth.

Follow-on Research

As current efforts to promote energy efficiency including advocacy groups, codes and standards and utility programs continue to produce energy savings it is important to understand emerging trends that impact efficiency.

Understanding end-use consumption and emerging technologies is key in this effort. As mentioned earlier there are key technologies that are expected to play a continuing role in energy efficiency while at the same time offering new opportunities for customer flexibility. Some key areas to consider include:

- Advanced motor technologies,
- Advanced thermal technologies such as heat pumps with expanded market potential in colder climates,
- More efficient electronics incorporating advanced materials, batteries and power management,

- Emerging electric end-use categories such as smart phones and tablets, and electric transportation.

Codes and standards continue to identify new areas for energy efficiency efforts and at the same time new end-uses continue to emerge creating new opportunities for energy savings. As the technology landscape unfolds the realm of cost-effective efficiency will also continue to change.

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Section 1: Introduction

Electricity plays an integral role in supporting the standard of living to which we have grown accustomed, enabling comfort, convenience, health and safety, security, and productivity in its traditional end-use applications, including air conditioning, lighting, refrigeration, and motive power. Moreover, the computational and communications infrastructure associated with our digital economy depends on electricity – from powering data centers to charging ever-proliferating mobile electronic devices.

Electricity consumption in the residential, commercial and industrial sectors is expected to increase 22% between 2012 and 2035.

Our nation's usage of electricity to power homes, buildings, industrial facilities and public areas is expected to increase by 22% between 2012 and 2035, according to the U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2012 (*AEO2012*) baseline.[9] The projected compound annual growth rate (CAGR) for the residential, commercial and industrial sectors is forecast to be 0.85% between 2012 and 2035. Although steady growth is predicted, the AEO forecast of growth in electricity consumption has been declining year over year accounting for shifts in the economy, energy prices, and technology innovation among other things.

Understanding growth in demand is key for electric service providers at all levels as they plan resources to meet customers' needs while maintaining reliable operation of the power system. The challenge to provide affordable, reliable and environmentally responsible electricity incents providers to understand all resources available to continue to meet demand. Utilities and policy makers continue to look to energy efficiency as a cost-effective resource to enable reliable and affordable electric service while at the same time reducing carbon emissions.

In 2009 the Electric Power Research Institute commissioned a study to assess the potential energy savings achievable through energy efficiency and demand response programs in the U.S. from 2010 through 2030.[10] This study updates the 2009 assessment of potential from energy efficiency programs with several enhancements to the modeling engine, treatment of end uses, and a shift to the *AEO2012* baseline. A key objective of the study is to inform utilities, electric system operators and planners, policymakers, and other electricity sector industry

[9] "Annual Energy Outlook 2012 with Projections to 2035," U.S. DOE EIA, Washington DC, DOE/EIA-0383(2012), June 2012. http://www.eia.gov/forecasts/aeo/pdf/0383%282012%29.pdf

[10] *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.: (2010-2030).* EPRI, Palo Alto, CA: 2009. 1016987.

stakeholders in their efforts to develop actionable savings estimates for end-use energy efficiency programs.

The majority of the effort focused on the identification of cost-effective energy efficiency and assessment of the impacts of application of cost-effective efficiency measures beginning in 2013 through 2035. In addition to savings from energy efficiency programs, this report presents high-level impacts from the substitution of highly efficient electric technologies for fossil fueled end-uses to provide for a holistic view of the combined impact of energy-efficient electrification.

The study began with development of baseline forecasts of electricity consumption absent any new utility programs or other programs administered by state agencies or third parties. The forecasts are consistent with the *AEO2012* Reference case and the 2011 Demand Technology case for electricity consumption. The study estimates the potential for annual energy efficiency for the years 2013 through 2035 at the end-use level for the residential, commercial, and industrial sectors. This analysis yields forecasts of changes in electricity use, and summer and winter coincident peak demand, for the U.S. by each of the ten Census divisions and three states (CA, FL and TX) as shown in Figure 1-1.

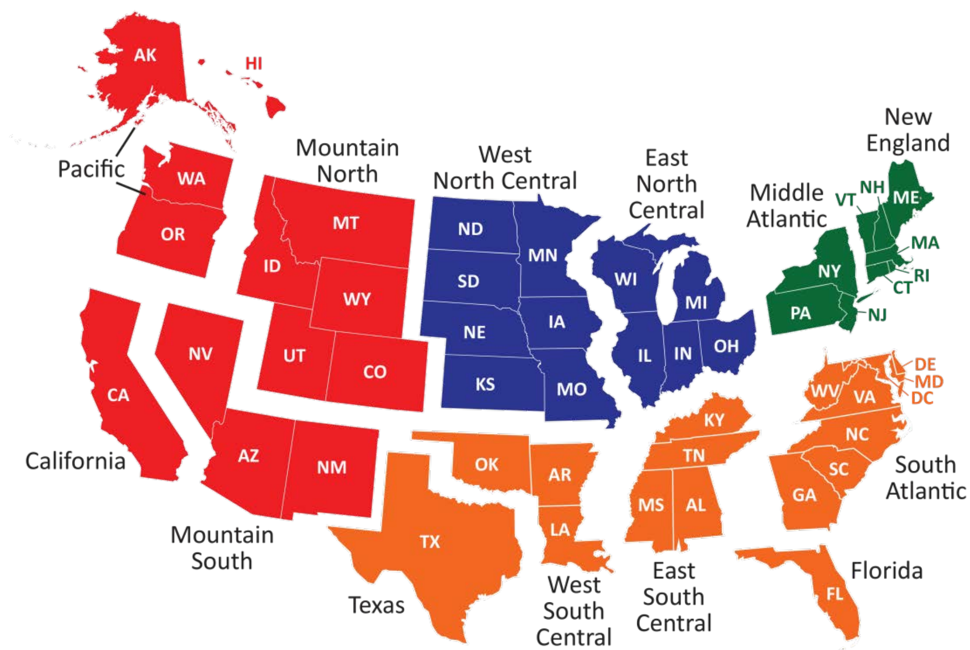


Figure 1-1
Geographic Divisions – Ten Census Divisions plus Three States

Section 2 describes the methodology employed in this study, which features a micro-economic model based on equipment stock turnover to construct a bottom-up estimate of savings potential at the end-use level in the residential and commercial sectors, and a top-down estimate of savings in the industrial sector.

The first key analytical step was to develop baseline forecasts of electricity consumption, and summer and winter peak demand consistent with the

AEO2012 forecasts, without the impact of utility programs, calibrated at the U.S. Census division, sector, end-use, and technology levels. This procedure is described in Section 3.

Drawing from EPRI's established database of energy-efficient measures savings and costs and applying sequential technical, economic, and market screens, we estimated the potential annual savings achievable from energy efficiency and programs for the years 2013 through 2035 at the end-use level for the residential, commercial, and industrial sectors for the U.S. and ten Census divisions and three states (CA, FL and TX). Section 4 details the energy savings results and Section 5 details the corresponding peak demand reduction results.

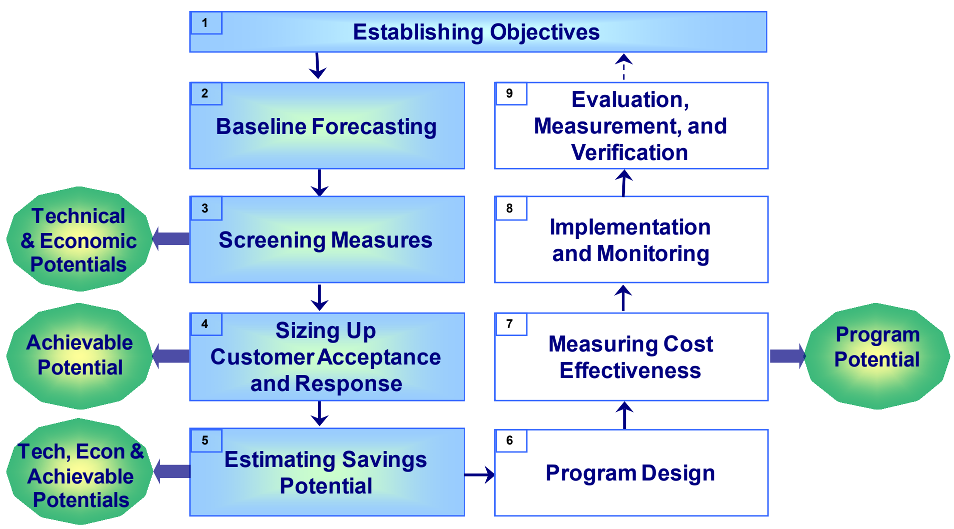
Energy efficiency programs implemented by utilities or agencies require significant investments in administration, marketing, promotion, and financial incentives. Section 6 provides supply curves for achieved energy efficiency potential and an estimate of costs associated with achievable potential.

The potential impacts of energy efficiency programs detailed in Sections 4 and 5 are predicated on the identical set of economic assumptions set forth by the EIA, including a relatively flat electricity price forecast in real dollars between 2012 and 2035, no presumption of carbon policy or monetization, and no presumption of new building efficiency codes or appliance efficiency standards beyond what has already been enacted. High-level estimates of electricity consumption for on-road and non-road electric transportation are provided in Section 7, and a high-level estimate of growth in demand from the adoption of highly efficient electric technologies replacing fossil-fueled technologies is presented in Section 8.

The study concludes with a summation in Section 9 and a call for additional follow-on research to further the study of energy efficiency.

Section 2: Energy Efficiency Potential Analysis Approach

This study implemented an analysis approach consistent with the methods described in EPRI's Energy Efficiency Planning Guidebook,[11] published in June 2008, and the National Action Plan for Energy Efficiency (NAPEE) Guide for Conducting Energy Efficiency Potential Studies,[12] published in November 2007. The same approach was applied in EPRI's Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.[13] published in 2009 (the 2009 National Study). Figure 2-1 illustrates the framework for this analysis, represented as steps one through five of the energy efficiency planning process as documented in the EPRI Energy Efficiency Planning Guidebook.



Source: Energy Efficiency Planning Guidebook, EPRI 1016273, June 2008

Figure 2-1
General Energy Efficiency Analysis Framework

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[11] *Energy Efficiency Planning Guidebook.* EPRI, Palo Alto, CA: 2008. 1016273.

[12] P. Mosenthal and J. Loiter, "Guide for Conducting Energy Efficiency Potential Studies," U.S. EPA, Arlington, VA, 2007.

[13] *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.: (2010-2030).* EPRI, Palo Alto, CA: 2009. 1016987.

This section details the analysis approach and data development applied in this study, beginning with the list of enhancements and additions that have been implemented in the current study. Following this is a description of the development of baseline electricity use in 2012. This is followed by a description of the development of baseline forecasts for annual electricity use and summer and winter peak coincident demand. The section concludes with a description of the modeling approach used to estimate annual electricity and demand savings resulting from energy efficiency.

Key Updates and Enhancements from the 2009 National Study

EPRI's efficiency model database is continually updated for utility studies with guidance from EPRI's technical experts. These updates capture changes to technology available to customers and changes to the characteristics of these technologies. EPRI's experts expand the data to capture the latest technologies available to customers and vet existing technology savings and cost data. As such, all updates to the measure database are included and information on the measures is available in the Appendices.

Table 2-1 lists structural changes implemented since the 2009 study. To begin with the baseline forecasts were updated to the *AEO2012*. The 2009 National Study treated four Census regions, which have been broken into their constituent ten Census divisions. In addition three of the largest states are treated separately, Florida, Texas and California (see Table 2-3). This level of geographic specificity is particularly important for weather-sensitive end uses whose consumption and usage patterns may vary significantly depending on climate. End-use intensity also varies significantly by building type therefore the model was updated to include sub-segments for both the residential and commercial sectors. These changes to sub-divisions allow a more rigorous and accurate analysis of achievable savings.

To better represent the evolution of end-use consumption over the forecast period, the effects of codes and standards currently planned are included. The main impacts of codes and standards are changes to the consumption and peak demand of the base technology. As codes and standards tighten, the newly installed equipment will consume less energy and typically have lower peak demand. In addition, a change in base technology leads to a change in the efficient measures available to replace the technology.

The National Appliance Energy Conservation Act of 1987 included minimum efficiency levels for refrigerators and freezers, which manufacturers had to meet beginning in 1990. These standards have since been updated, most recently in 2011[14] requiring refrigerators and freezers to consume on average 25% less energy per unit – 25% lower unit energy consumption (UEC). The impact in the model is a reduction of the baseline technology UEC by 25%. The result is a change in

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[14] Amended standard available from the Code of Federal Regulations, 10 CFR 430.32(a): http://www.gpo.gov/fdsys/pkg/CFR-2012-title10-vol3/pdf/CFR-2012-title10-vol3-sec430-32.pdf

the marginal savings and costs for the remaining measures relative to this new baseline technology, and in effect a change in the benefit-cost ratios and the passing efficient measures.

Table 2-1
Structural Changes to the Model

Structural Changes
Baselines updated to *AEO2012*
Greater sub-regional specificity: ten Census divisions plus three states (FL, TX, CA)
Inclusion of multiple building segments for residential and commercial sectors
Incorporation of current codes and standards
Re-evaluation of technology cost-effectiveness every year
Capability to evaluate cost-effectiveness using the TRC, PT, UCT, RIM or SCT benefit-cost ratio

Note: TRC = total resource cost test; PC = participant cost test; UCT = utility cost test; RIM = ratepayer impact measure; SCT = societal cost test

Evaluating technology cost effectiveness each year allows measures that are not cost-effective to have an impact as avoided costs and technology costs change over time. This also allows for changes in passing measures as baseline technologies change with codes and standards. The overall impact is a much more dynamic assessment of energy and demand savings due to the time-varying nature of the passing measures.

Five standard energy efficiency benefit-costs tests are available for use in evaluating measure cost-effectiveness in the model. The Total Resource Cost test (TRC) is the test used for the main results presented in this report. The other cost tests are available for scenario analysis and individual customer use.

Table 2-2 summarizes additional updates to the model.

Table 2-2
Additional Enhancements to the Model

Modeling
Enhanced lighting model, coupling lumen replacement with physical stock turnover
Future technology included to capture technology innovation, beginning after 2020
Decreasing equipment cost trajectory, beginning after 2020
More robust treatment of heat pumps as an end use

The lighting modeling was rebuilt coupling a lumen replacement approach with the physical turnover of lamp stock following the 2009 National Study. For the most part, efficient technologies are evaluated on a per-lumen basis to provide an equivalent light output when compared to the baseline technology. For most technologies the power consumed and lamp cost are normalized to the base technology’s lumen output. The primary exception is light emitting diode or

LED lamp technologies where the directionality of the light source allows the lamp to produce less lumens while still providing the same level of useful light output.

To better capture the different components in linear fluorescent technologies the costs of replacing ballasts and fixtures were also considered. The baseline linear fluorescent technology is a hybrid of T8 and T12 fixtures. If an efficient technology requires a change in fixture and or ballast that cost is included as appropriate. In addition since the lamps, fixture and ballast need to be replaced at varying intervals, an amortized cost is used to perform the economic screen and in the stock turnover model.

In the 2009 National Study the cost-effectiveness was determined using a variant of the Participant Test. In the current study the Total Resource Cost test was applied to better capture the cost-effectiveness required of utilities from a regulatory standpoint. The benefits are evaluated using avoided costs and the cost is the technology incremental cost plus a nominal program administration cost.

Where cost-effectiveness was evaluated once in the base year, cost effectiveness is now evaluated each year. With a forecast of avoided costs, and evolving technology (due to codes and standards) there are changes to what measures are cost effective year over year.

With dynamics built into the base technologies and cost-effectiveness it was also appropriate to include provisions for evolution in technology and technology cost. This is captured by including a “future technology” in the major end use categories that has a higher efficiency and higher cost than the existing technologies. These future technologies are included beginning in year 2020 and represent innovative technologies that are not currently available to customers. In most cases the future technologies do not pass the economic screen due to their higher cost, but are present in the technical potential.

It is also assumed that the cost of technologies will reduce over time due to increased market penetration and as newer technologies come to market. The decrease in technology incremental cost is implemented as a savings growth rate that works to reduce the cost each year after 2020. The decrease in incremental cost is calculated as a scaling factor applied to all measure costs as shown in Equation 2-1.

$$CostMultiplier = \frac{1}{(1+g)^y} \qquad \text{Eq. 2-1}$$

Technology Cost Savings

Where g is the savings growth rate and y is the current year minus the base year (2020). As the simulation progresses, the cost savings grow. With a savings growth rate of 1.5%, in the forecast year of 2035 the final cost multiplier is 79.99%. This is equivalent to about a 20% decrease in equipment incremental cost in 2035.

Cost savings occur from either a drop in real prices due to changes in supply and demand or from improvements in productivity caused by technological improvements. The Bureau of Economic Analysis of the Department of Commerce estimates productivity increases for both capital and labor. Between 1960 and 2000 the productivity of capital was 1.8%. Since 2000 productivity was much lower at 0.3%. For the purposes of this analysis a value of 1.5% was used. The value was applied to the total costs to reflect the reduction in real terms of energy efficiency capital and labor.

Segmentation by Region, Customer Type and Building Type

Estimates of baseline consumption and demand, as well as forecasts of measure-based savings potentials, were developed for the U.S. as a whole, ten U.S. Census divisions and three states.

This includes eight Census divisions: New England, Middle Atlantic, East North Central, West North Central, South Atlantic, East South Central, West South Central, and Pacific. The ninth Census division, Mountain, has been broken out into Mountain North and Mountain South. To achieve better granularity California, Florida and Texas have been broken out from their respective Census divisions of Pacific, South Atlantic and West South Central. This increases the granularity of the study compared to the 2009 National Study which considered four Census regions. The resulting thirteen geographic divisions are shown in Table 2-3.

Table 2-3
Geographic Divisions

Division	States
Northeast Census Region	
New England	NH, VT, ME, MA, RI, CT
Middle Atlantic	NY, NJ, PA
Midwest Census Region	
East North Central	WI, MI, IL, IN, OH
West North Central	ND, SD, MN, NE, IA, KS, MO
South Census Region	
South Atlantic	WV, VA, DE, MD, DC, NC, SC, GA
Florida	FL
East South Central	KY, TN, MS, AL
West South Central	OK, AR, LA
Texas	TX
West Census Region	
Mountain North	MT, ID, WY, UT, CO
Mountain South	AZ, NM, NV
Pacific	WA, OR, AK, HI
California	CA

For each of the geographic divisions, the electricity usage was analyzed for the three principal customer segments – residential, commercial and industrial.

The residential and the commercial sectors were further broken out into different building types. In the current study the analysis by building types is available at the national level but not at each geographic level. Baseline consumption and potential savings forecasts were determined for each of the different building types. For the residential sector, the building types include those shown in Table 2-4.

Table 2-4
Residential Building Segments

Residential Building Type
Single Family
Multi-Family
Mobile Homes

For the commercial sector, the building types are parallels to EIA's Annual Energy Outlook building types, as shown in Table 2-5.

Table 2-5
Commercial Building Segments

Commercial Building Type
Retail
Office-Large
Office-Small
Education
Warehouse
Assembly
Health Care
Food Service (which are mainly restaurants)
Food Sales (which are mainly shops selling food)
Lodging
Other

In order to obtain the required resolution in both modeling and reporting, each sector was further divided by electricity consuming end-use category, and ultimately, by power-consuming technology as illustrated in Figure 2-2.

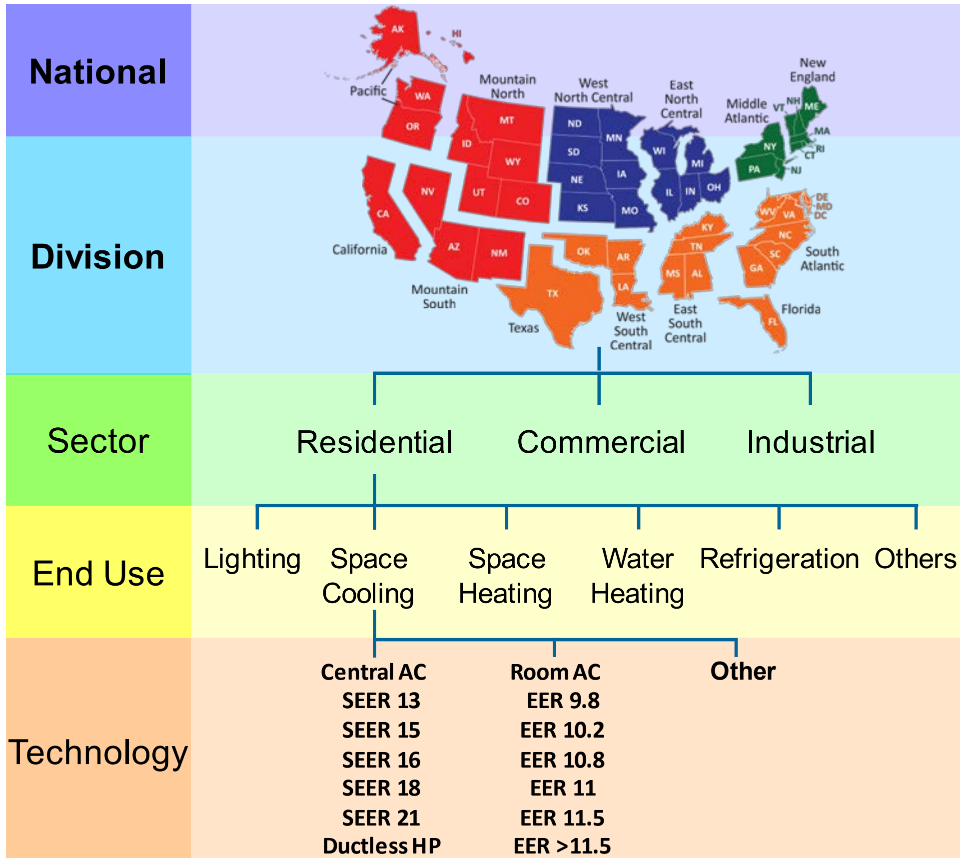

Figure 2-2
Example Segmentation of Electricity Consumption Applied in Modeling

Base-Year Market Profiles

As a first step to assessing the potential for energy efficiency, electricity usage in the base year (2012) was analyzed along the sector and then end-use level. This study applies baseline forecasts for electricity use by sector and end use from the *AEO2012*.[15] Electricity usage is segmented by end use and technology for the residential and commercial sectors, largely along the same lines as the AEO. For the industrial sector the AEO reports usage in aggregate and by industrial excluding refining, and refining alone.

As a supplement to the *AEO2012* base-year data, additional sources were incorporated into the analysis in order to attain a suitable level of resolution. EIA survey results such as the 2009 Residential Energy Consumption Survey (RECS)[16], and the 2003 Commercial Building Energy Consumption Survey

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[15] "Annual Energy Outlook 2012 with Projections to 2035," U.S. DOE EIA, Washington DC, DOE/EIA-0383(2012), June 2012. http://www.eia.gov/forecasts/aeo/pdf/0383%282012%29.pdf

[16] "2009 Residential Energy Consumption Survey," U.S. DOE EIA, Washington DC, Oct. 2012. http://www.eia.gov/consumption/residential/

(CBECS)[17] provide additional detail about the specific technologies, such as equipment vintage and unit energy consumption. The 2010 Manufacturing Energy Consumption Survey (MECS)[18] provides consumption information at the 3-digit NAICS code level for the Census regions.

Baseline Forecast Development and Summary

The next step in the estimation of potential savings is the development of a baseline forecast. This provides insight into energy-saving opportunities as well as a context in which to interpret the results. The baseline forecast employed in this study, like the base-year consumption data, is grounded in the *AEO2012* forecast. As a widely recognized macroeconomic modeling effort spanning the entire energy industry, the AEO serves as a credible foundation to the present study. The AEO forecasts for electricity consumption were adjusted and resolved to meet the requirements of this study, as described below. The end result is the development of the two forecasts – energy and system peak demand – for the years 2012, 2015, 2025 and 2035 presented in the following section.

The baseline forecasts are broken down to the divisional, sector, building type, end use, and technology levels to provide the level of detail necessary to estimate the future potential of energy efficiency programs and activities implemented by utilities or other organizations. Detailed information at these levels brings to light regional differences in program barriers and market conditions that affect the savings potential of energy efficiency programs. In addition, because energy efficiency programs and activities are focused at the technology level, disaggregating the forecasts to the end-use and technology levels provides the most useful and insightful information.

The national forecast by sector was broken down into the same geographical and building segments that we have set forth in Table 2-3, Table 2-4, and Table 2-5. This geographical division provides more granularity than that used by the U.S. Census Bureau to project population and economic figures.

Energy Forecast

The energy baseline forecast is derived from *AEO2012* projections generated by the EIA using the National Energy Modeling System (NEMS). In addition to its use in the development of the AEO projections, NEMS is also used in analytical studies for the U.S. Congress, the White House, and other offices within the Department of Energy. NEMS takes into account a multitude of economic, financial, technological, environmental, legislative, and regulatory assumptions to generate the projections.

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[17] "2003 Commercial Buildings Energy Consumption Survey," U.S. DOE EIA, Washington DC, Sept. 2008. http://www.eia.gov/consumption/commercial/

[18] "2010 Manufacturing Energy Consumption Survey," U.S. DOE EIA, Washington DC, March 2013. http://www.eia.gov/emeu/mecs/

The *AEO2012* Reference case, illustrated in Figure 2-3, is a policy-neutral case used as the starting point for the energy forecast, which assumes current policies affecting the energy sector remain unchanged throughout the projection period (2012 to 2035).

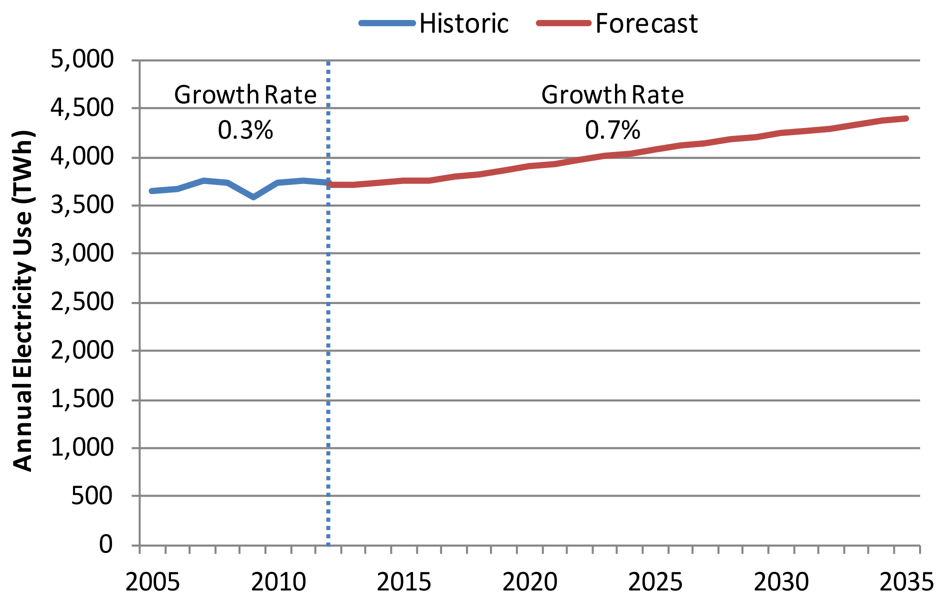

Figure 2-3
Annual Energy Outlook 2012 Electricity Forecast

The *AEO2012* Reference case includes market-driven (or "naturally occurring") energy efficiency impacts and some level of future energy efficiency program impacts. Ideally, only naturally occurring impacts are included in the energy baseline since these impacts happen outside the influence of utility- or government-sponsored energy efficiency programs and are going to materialize anyway.

To avoid double-counting the impacts of energy efficiency measures identified in this study, the estimated impacts of future energy efficiency programs "embedded" in the *AEO2012* Reference case must be removed. This operation is performed by first estimating this embedded program savings and then "adding it back" to the *AEO2012* Reference case to construct an adjusted baseline forecast.

To estimate the embedded impact of energy efficiency programs, we compared the *AEO2012* Reference case to another *AEO2012* forecast of electricity consumption known as the 2011 Demand Technology case, which does not include the impacts of either energy efficiency programs or market-driven energy efficiency improvements. The difference between the two cases is attributable to market-driven energy efficiency and energy efficiency programs. A share of this difference was allocated to energy efficiency programs by sector, based on the expert judgment of experienced energy efficiency program practitioners, and this value was added back to the *AEO2012*Reference case for the residential and commercial sectors. In the industrial sector the 2011 Demand Technology is lower than the Reference case forecast in most years. The difference between the two forecasts in any year is less than 1.3%. Without knowing how to interpret this difference and because it is relatively small, the Reference case forecast is used for the industrial sector.

The estimates of embedded energy efficiency impacts are summarized in Table 2-6 and illustrated in Figure 2-4. This adjusted baseline forecast is presented in greater detail in Section 3 and used throughout the report to present results.

Table 2-6
Effects of Existing Energy Efficiency Added into Baseline Energy Forecast

	2025	2035
AEO2012 Reference Case (TWh)	4,078	4,393
Adjusted Baseline Forecast (TWh)	4,177	4,529
Embedded Savings (TWh)	99	136
Percentage of *AEO2012* Reference Case	2.4%	3.1%

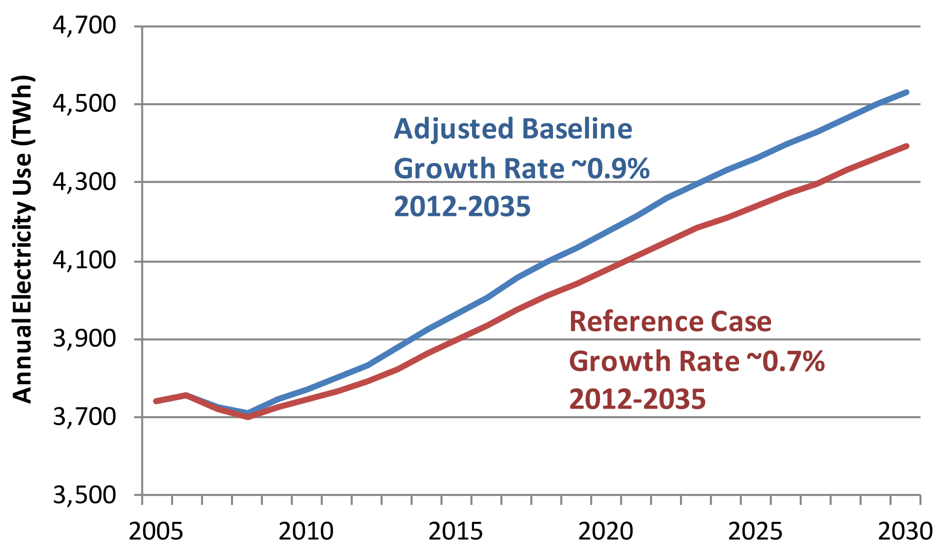

Figure 2-4
Comparison of AEO2012 Reference Case and Adjusted Baseline Forecast

Key Drivers

The macroeconomic drivers of the forecast include U.S. population, employment, Gross Domestic Product (GDP), value of shipments, housing starts, and building construction.

Table 2-7 presents recent history and forecasts of macroeconomic indicators from the *AEO2012* Reference Forecast, including the compound annual growth rate

(CAGR) for 2012-2035. Average growth in GDP between 2012 and 2035 is 2.6%, more than three times the 0.7% rate of electricity growth in the Reference case. This implies a decline in the electricity intensity per GDP from 0.28 kWh/GDP in 2012 to 0.18 kWh/GDP in 2035, a decrease of about 35%.

Table 2-7
AEO2012 Reference Case – Macroeconomic Indicators (billion 2005 chain-weighted dollars, unless otherwise noted)

Macroeconomic Indicators	2012	2015	2025	2035	CAGR
Real GDP	13,486	14,803	19,185	24,539	2.6%
Energy Intensity (kBtu per 2005 dollar of GDP)					
Delivered Energy	5.30	4.84	3.85	3.17	-2.2%
Total Energy	7.26	6.58	5.32	4.36	-2.2%
Value of Shipments(billion 2005 dollars)					
Total Industrial	5,939	6,730	7,973	8,692	1.7%
Non-manufacturing	1,539	1,873	2,228	2,407	2.0%
Manufacturing	4,400	4,857	5,745	6,285	1.6%
Energy Intensive	1,566	1,664	1,901	2,034	1.1%
Non-energy Intensive	2,834	3,194	3,844	4,251	1.8%
Population and Employment (millions)					
Population*	316.9	326.2	358.1	390.1	0.9%
Population (16+)	249.3	256.5	282.6	309.6	1.0%
Population (65+)	42.8	47.1	64.2	77.7	2.6%
Employment, Nonfarm	131.8	139.4	154.2	166.8	1.0%
Employment, Manufacturing	11.7	12.1	11.4	9.2	-1.1%
Key Labor Indicators					
Labor Force (mill.)	154.2	158.0	168.6	181.7	0.7%
Nonfarm Labor Productivity (2005=1)	1.12	1.16	1.42	1.75	2.0%
Key Indicators for Energy Demand					
Real Disposable Personal Income	10,305	11,035	14,286	18,217	2.5%
Housing Starts (millions)	0.71	1.75	1.96	1.89	4.4%
Commercial Floorspace (billion ft^2)	82.4	84.1	93.9	103.0	1.0%

* With armed forces overseas.

Energy prices, particularly electricity prices, are another key driver in the electricity forecast. EIA projects retail electricity prices to remain relatively flat in real dollars between 2012 and 2035, with residential and industrial prices to slightly increase over that period, shown in Figure 2-5.

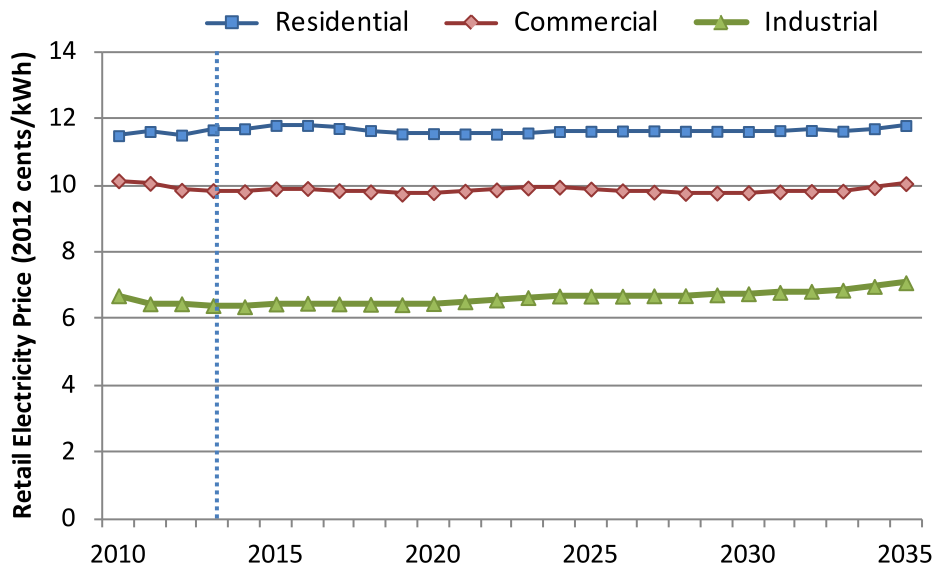

Figure 2-5
Retail Electricity Price Forecast by Sector (AEO2012)

Table 2-8 presents forecasts of U.S. electricity and natural gas prices by sector from the *AEO2012*. Natural gas prices are forecast to increase marginally over the next twenty years with electricity prices expected to remain relatively flat in the *AEO2012*. Changes in the relative prices of natural gas and electricity will impact the cost effectiveness of energy efficiency and fuel switching.

Table 2-8
AEO2012 Reference Forecast – Electricity and Natural Gas Prices by Sector

Macroeconomic Indicators	2012	2015	2025	2035	CAGR
Electricity Prices (2010 cents per kWh)					
Residential	11.5	11.8	11.6	11.8	0.1%
Commercial	9.9	9.9	9.9	10.1	0.0%
Industrial	6.5	6.5	6.7	7.1	0.4%
Natural Gas Prices(2010 dollars per million Btu)					
Residential	10.52	10.31	12.03	13.98	1.2%
Commercial	8.68	8.60	10.02	11.64	1.3%
Industrial	4.41	4.88	6.04	7.54	2.4%

While capable of driving changes in consumption patterns and influencing the future role of energy efficiency programs, price plays a marginal role in this study because of the relatively flat trend in electricity prices assumed by EPRI. The price forecast used in this study is presented in Section 3.

In addition to the macroeconomic and social indicators assumed in the forecast, the baseline takes into consideration the effects of legislation enacted as of 2012. The baseline assumes compliance with codes and standards already signed into law, while it does not presume the enactment of new efficiency codes and standards. This approach to the potential impacts of codes and standards on future energy use is consistent with the treatment employed in the *AEO2012* forecast. For example, the federal efficiency standard for central air conditioners is SEER 14 beginning in 2015.[19] The baseline forecast assumes that each unit purchased beginning in 2015, whether for retrofit or new construction, will meet or exceed this level of efficiency. More recently, the Energy Independence and Security Act (EISA), signed into law in 2007[20], establishes new efficacy requirements for lighting technologies. This standard influences the baseline forecast for residential lighting, which is discussed in the baseline section.

Peak Demand Forecast

The end-use coincident peak demand forecasts are calculated from the bottom up for both summer and winter months. End-use load factors and coincidence factors are used to calculate peak demand per unit from the annual energy use information. This demand and the stock forecast are used to calculate aggregate annual end-use demand; the demand forecast is then equi-proportionally adjusted to align with the *AEO2012* baseline end-use energy forecast.

Table 2-9 details the definitions used for summer and winter system coincident peak in all sectors. This is the end-use level, peak or hourly demand (kW) that coincides with the system peak. In building modeling tools, this period is used to determine the incremental energy and demand savings for weather-sensitive measures from end-use level 8760 data. The general modeling approach used to construct the energy and demand baselines is discussed later in this section.

Table 2-9
Summer and Winter Coincident Peak Definitions

	Summer	Winter
Months	June, July, August, September	December, January, February, March
Days	Monday - Friday	Monday - Friday
Hours	Hours ending 16-20	Hours ending 6-11

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[19] Amended standard available from the Code of Federal Regulations, 10 CFR 430.32(a): http://www.gpo.gov/fdsys/pkg/CFR-2012-title10-vol3/pdf/CFR-2012-title10-vol3-sec430-32.pdf

[20] “H.R. 6--110th Congress: Energy Independence and Security Act of 2007.” www.GovTrack.us. 2007. Oct. 2013. http://www.govtrack.us/congress/bills/110/hr6

Estimation of Energy Efficiency Impacts

The general approach for estimating the potential savings from energy efficiency involves two steps:

1. Developing a list of efficient measures along with unit impacts and pertinent market data for each measure, and
2. Phasing these measures into general use, with equipment choice moderated by the various potential definitions included in the project framework.

Each of these steps is described in the following sections.

Energy Efficiency Measures List

The first step toward estimating savings through energy efficiency is to identify specific efficient technologies and measures (collectively referred to here as "measures") for consideration. While the selection of energy-efficient measures should be as inclusive as possible in order to reflect the full potential for savings, the wide scope of these studies requires that measures be broadly applicable and not overly detailed.

The task of assembling a robust, comprehensive list of available efficiency measures began with the measure database included in the 2009 National Study. This original measure list was a comprehensive survey of several previous energy efficiency potential studies. Because most of those studies were performed at the individual utility level, it was necessary to aggregate and generalize the measures to obtain the appropriate level of applicability. These measures were then compared against the proprietary Database for Energy Efficiency Measures (DEEM) maintained by Global Energy Partners to yield a more comprehensive list of measures and their associated energy impact and pertinent cost information. The resulting comprehensive list of energy efficiency measures was then benchmarked against those applied in recent potential studies, resources such as California's Database for Energy Efficient Resources (DEER), and those developed by energy efficiency organizations such as the American Council for an Energy-Efficient Economy (ACEEE).

In the interim as EPRI has conducted studies for individual utilities this measure database has been updated based on input from EPRI's technical experts and other industry agents. These updates captured new technologies that have come to market since the 2009 National Study. Measure life and cost data has also been re-evaluated using external literature and input from EPRI staff. In addition coincident peak demand and seasonal energy splits were added to capture loadshape impacts of efficient technologies.

Savings from measures in weather-dependent end uses were also re-assessed periodically using engineering models such as EnergyGauge® for the residential sector and eQUEST for the commercial sector.[21, 22]

Table 2-10 and Table 2-11 summarize the categories of energy efficiency measures in the residential and commercial sectors included in this study, respectively.

Table 2-10
Residential Sector Energy Efficiency Measure Categories

Central AC	Storm Doors
Air-Source Heat Pumps	External Shades
Ground-Source Heat Pumps	Ceiling Insulation
Room AC	Foundation Insulation
AC Maintenance	Foundation Insulation
HP Maintenance	Wall Insulation
Attic Fan	Windows
Furnace Fans	Reflective Roof
Ceiling Fan	Reflective Roof
Whole-House Fan	Duct Repair
Duct Insulation	Infiltration Control
Programmable Thermostat	Dehumidifier
Water Heating	Dishwashers
Faucet Aerators	Clothes Washers
Pipe Insulation	Clothes Dryers
Low-Flow Showerheads	Refrigerators
Dishwashers (Domestic Hot Water)	Freezers
Furnace Fans	Cooking
Lighting – Linear Fluorescent	Televisions
Lighting – Screw-in	Personal Computers
Enhanced Customer Bill Presentment	Smart Plugstrips, Reduce Standby Wattage

Notes: AC = air conditioning; HP = heat pump.

[21] EnergyGauge, Energy and Economic Analysis Software, University of Central Florida, Cocoa, FL. http://www.energygauge.com/

[22] eQUEST, The Quick Energy Simulation Tool. http://doe2.com/equest/

Table 2-11
Commercial Sector Energy Efficiency Measure Categories

Heat Pumps	Fans, Energy-Efficient Motors
Central AC	Fans, Variable Speed Control
Chiller	Programmable Thermostat
Cool Roof	Variable Air Volume System
VSD on Pump	Duct Testing and Sealing
Economizer	HVAC Retro-commissioning
EMS	Efficient Windows
Roof Insulation	Lighting – Linear Fluorescent
Duct Insulation	Lighting – Screw-in
Water Heater	High-Efficiency Compressor
Water Temperature Reset	Anti-Sweat Heater Controls
Computers	Floating Head Pressure Controls
Servers	Installation of Glass Doors
Displays	High-Efficiency Vending Machine
Copiers Printers	Icemakers
Other Electronics	Reach-in Coolers and Freezers

Notes: AC = air conditioning; VSD = variable speed drive; EMS = energy management systems; HVAC = heating, ventilation, and air conditioning.

Modeling Approach

For the residential and commercial sectors, a bottom-up approach was applied to estimate potential, which required detailed microeconomic modeling at the end-use level. To this end, EPRI developed a stock accounting-based model that estimates energy savings and peak demand reduction for each end use within a given division and sector. The model uses stock accounting to determine the percentage savings reduction in electricity consumption and peak demand for each end use considered in this study. The model tracks the number of end-use devices by vintage and average efficiency level for each year in the forecast period. The model assumes that equipment is replaced after its useful life and incorporates a decay rate for the oldest stock and a replacement rate for newer stock. The annual energy use is calculated as the product of the number of end-use devices and the average annual energy contribution per device. The number of devices is the product of the number of households and the device saturation, where the device saturation is defined as the average number of devices per household. The model baseline is also dynamic in the sense that it captures changes in efficiency due to efficiency standards coming into effect throughout the period of study.

The calibrated baseline provides the reference point for determination of the energy savings reduction for each end-use category. The savings in each end use and at each potential level are equi-proportionally applied to the *AEO2012* end-use level baselines to determine the potential savings presented in this report. This allows the savings relative to the *AEO2012* baseline to be presented, while the end-use level savings percentage within each division has been preserved.

Figure 2-6 illustrates the mechanics of the calculation with input data in green, estimated inputs in yellow. These are then used in the model engine (in blue) to generate outputs.

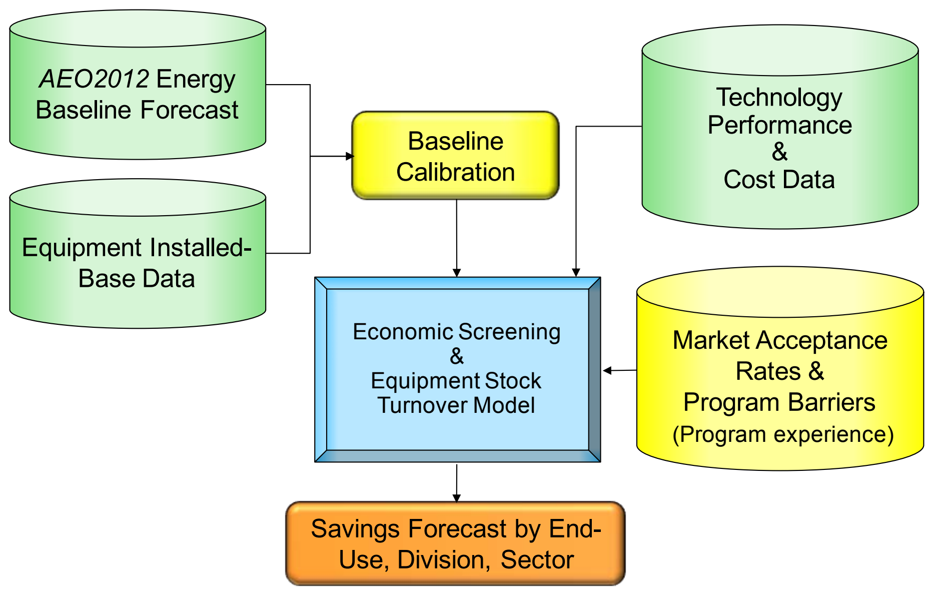

Figure 2-6
Overall Analysis Approach

Equipment Model

The first task executed by this model is a bottom-up estimate of energy use based on market and technical data such as vintage and efficiency of existing stock, relative efficiency levels of current shipments, and unit energy consumption. This level of resolution was possible within the residential and commercial sectors. Within this stock accounting framework, a set of efficiency measures is introduced and phased into general use as equipment turns over.

A model baseline is developed by aggregating the energy use by each technology and end use within a given sector and geographic division. The choice of efficiency measure to replace the base technology choice for a given end use is assessed every year by re-evaluating the most efficient cost-effective technology. This approach of continuous assessment throughout the modeling time period allows for a more realistic estimate of potential savings accounting for changes in costs, energy prices and technology evolution.

The energy consumption of technologies is adjusted for use in the stock turnover model to reflect different levels of energy efficiency potential. Once calculated the potential savings estimates are calibrated equi-proportionally to show savings relative to the AEO baseline.

Controls and Shell Model

While the phasing in of energy-consuming equipment according to the appropriate efficiency levels represents part of the potential savings, many of the energy efficiency measures cannot be treated through this approach. For example, consider the installation of an energy management system (EMS) in a large commercial office building. Because the power requirements of such a system are negligible in comparison to those of the entire building, a stock accounting model tracking such installations would reveal almost no potential for energy savings. However, because the EMS controls several systems for the entire building, including the heating, ventilation and air conditioning (HVAC) systems, it is likely to deliver significant electricity savings and a large peak demand reduction. Instead of accounting for the EMS through stock accounting, therefore, its associated energy savings potential is assessed through application of a savings fraction to the applicable load.

In this case, an EMS is assumed capable of a 17-31% reduction in cooling load and a 6-16% reduction in heat pump consumption, depending on climate zone, based on the best available supporting data. To assess the savings, then, the total energy consumption for the relevant end use under each case (technical potential, economic potential, etc.) is multiplied by the technical savings fraction and a saturation rate that grows throughout the forecast horizon. This approach was applied to all control and shell measures.

Industrial Model

The residential and commercial sectors have been the primary focus of detailed electricity forecasts and energy efficiency market research and potential studies for many years. This level of data resolution allowed a bottom-up modeling approach for these two sectors. By contrast, the industrial sector provides much less data resolution, due largely to the diverse array of highly specialized processes that take place in industrial facilities.

Because of its unique character, the industrial sector was modeled using a top-down analysis of the data available through *AEO2012* and other sources. Energy savings in the industrial model are calculated at the process level in each NAICS segment using model output from EIA's model Plant Energy Profiler, or PEP[23] (formerly called QuickPEP). These energy savings are then applied within each NAICS segment at the process level.

No technical potential is assessed for the industrial sector, the PEP results are used to determine economic, high achievable and achievable levels of potential.

[23] Plant Energy Profiler, U.S. DOE, released Nov. 10, 2011. https://ecenter.ee.doe.gov/EM/tools/Pages/ePEP.aspx

Developing Forecasts of Energy Efficiency Potential

Consistent with the 2009 National Study, four definitions of potential were used in this study.[24]

Technical Potential

The technical potential represents the savings due to energy efficiency and programs that would result if all homes and businesses adopted the most efficient, commercially available technologies and measures, *regardless of cost*. Replacement is assumed to occur at the end of their useful lives by the most efficient option available. Technical potential does not take into account the cost-effectiveness of the measures, or any market barriers.

Economic Potential

The economic potential represents the savings due to programs that would result if all homes and businesses adopted the most energy-efficient cost-effective commercially available measures. The economic test applied is a variation of the Total Resource Cost test (TRC), which compares projected avoided costs to the incremental cost of the measure plus program administration costs.

The following information is used to evaluate the potential savings for each efficiency measure:

- Incremental energy savings (kWh)
- Incremental summer and winter demand savings (kW)
- Incremental cost of measure relative to baseline measure
- Utility program administration cost, assumed to be 20% of the incremental measure cost
- Measure lifetime

With the efficiency measure inputs and avoided costs, the Total Resource Cost benefit-cost ratio is calculated over the life of the measure. The ratio compares the present worth of the avoided power supply costs to the incremental measure cost plus the energy efficiency program administration cost (20% of the incremental cost), as shown in the following equation.

$$\frac{\sum_{i=1}^{t}\left(\frac{AvoidedPowerSupplyCosts_i}{(1+r)^i}\right)}{1.2*IncrementalMeasureCost} \qquad \textit{Eq. 2-2}$$

Where:

- i = year in which costs or savings are incurred
- t = life of measure
- r = discount rate (real discount rate, varies by cost test and sector)

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[24] EPRI National Study, p. xiii-xiv.

Economic potential does not take into account market barriers to adoption. Within a measure category, if several measures pass with a benefit-cost ratio greater than or equal to 1.0, the most efficient measure (greatest energy savings) is adopted.

In each of the models, the initial outputs are a set of electricity and peak demand reduction values under the technical and economic potential cases. As described above, these potentials are the result of assumptions about the adoption of efficiency measures, whether through a stock accounting framework, a device saturation approach, or the application of savings values to the pertinent segments of the baseline. The next step is to obtain the achievable potentials through the introduction of market acceptance ratios and program implementation factors, which reflect known barriers to demand-side activities.

High Achievable Potential

The high achievable potential (HAP) takes into account those barriers that limit customer participation. These barriers can include perceived or real quality differences, aesthetics, customer inertia, or customer preferences for product attributes other than energy efficiency. HAP is estimated by applying market acceptance ratios (MARs) to the economic potential savings from each measure in each year.

The MARs capture the effects of market barriers which at a high level include transactional, informational, behavioral, and financial barriers. They are essentially scaling factors applied to the measure savings over time. They are defined in ten-year intervals and change over time (maximum of 100%) to reflect that market barriers are likely to decrease over time. The MARs can also be thought of as representing what exemplary energy efficiency programs have achieved, assuming that they have overcome market barriers to some extent.

Achievable Potential

Unlike the other potential estimates, the achievable potential (AP) represents a forecast of likely customer adoption. It takes into account existing market delivery, financial, political and regulatory barriers that are likely to limit the amount of savings that might be achieved through energy-efficiency programs. For example, utilities do not have unlimited budgets for program implementation. There can be regional differences in attitudes toward energy efficiency and its value as a resource. AP is calculated by applying a program implementation factor (PIF) to the HAP for each measure. The program implementation factors were developed by taking into account recent utility experience with such programs and their reported savings. These factors also change over time to reflect that programs may be able to achieve increased savings as programs mature.

These MARs and PIFs were initially developed for the 2009 National Study using a Delphi panel, and for the most part have remained the same. In 2013 updates were made to specific end uses in the residential and commercial sectors where enhancements where made to their modeling treatment. The updates to treatment of key end uses where MARs and PIFs were updated are detailed in Table 2-12.

A panel of experts was engaged to update these factors taking into account differences in energy efficiency programs across the country. A broad assessment of market and program barriers and the process used to update the MARs and PIFs are documented in a 2013 EPRI technical update.[25]

Table 2-12
End Uses with Updated Market Acceptance Ratios and Program Implementation Factors

End Use	Sector	Technology
Heat Pumps (space heating and cooling)	Residential	A heat pump replaces two pieces of equipment - existing non-heat pump primary electric heating and central AC.
	Residential	A heat pump replaces an existing air-source heat pump.
	Commercial	A heat pump replaces an existing heat pump.
Ground-Source Heat Pumps (heating and cooling)	Residential	Ground-source heat pump replaces an existing ground-source heat pump.
Water Heating	Residential	Units ≤ 55 gallons, standard in 2015 requires EF at least 0.95.
	Residential	Units > 55 gallons, standard in 2015 requires heat pump water heaters with EF of at least 2.0.
	Commercial	Stock is assumed to be large units, > 55 gallons. Heat pump water heaters are the primary applicable efficiency measure.
Screw-In Lighting	Residential and Commercial	Includes incandescents, CFLs and other Edison-style lamps. Baseline technology mix changes over time with an increasing number of CFLs, and standard incandescents replaced with EISA-compliant technology.
Linear Fluorescent Lighting	Residential and Commercial	Linear fluorescent lighting includes tube fluorescent lamps along with any necessary ballasts and fixtures. The baseline is a mix of T12 and T8.
HID Lighting	Commercial	Indoor high-bay HID lighting. Baseline technology is metal-halide with a magnetic ballast.
Outdoor Street and Area Lighting	Commercial	Outdoor street and area lighting. Baseline stock is split into two categories: metal-halide, and high-pressure sodium/mercury-vapor.

[25] *Market Acceptance Ratio and Program Implementation Factor Development Guide.* EPRI, Palo Alto, CA: 2013. 3002001418.

Section 3: The Baseline Forecast

This section presents electricity profiles for the U.S. in the base year of 2012, and establishes a baseline forecast of electricity use, and summer and winter peak coincident demand by sector and end use.

The focus of this analysis is on energy efficiency potential in the residential, commercial, and industrial sectors, as such the baseline data presented does not include electricity for transportation. The *AEO2012* transportation forecast is less than a percent of total electricity consumption therefore the baselines presented herein account for nearly all AEO forecast electricity consumption.

Baseline forecasts for electricity consumption and summer and winter coincident peak demand are presented in the following sections. The electricity use forecast is based on the *AEO2012* Reference case and the *AEO2012* 2011 Demand Technology case. The Reference case includes some level of assumed energy efficiency adoption which may be naturally occurring, resulting from efficiency programs, or due to technology innovation. The 2011 Demand Technology case freezes technology options at the 2011 level, thereby removing the impacts of energy efficiency that are implicitly assumed in the Reference case.

The residential and commercial forecasts used in this analysis add the assumed impacts of energy efficiency achieved through efficiency programs and technology innovation. As a result, naturally occurring efficiency is captured in the forecasts. However, the assumed impacts of energy efficiency achieved through efficiency programs and technology innovation are not captured. This eliminates double counting of efficiency impacts resulting from the potential analysis. In the industrial sector the 2011 Demand Technology is lower than the Reference case forecast in most years. The difference between the two forecasts in any year is less than 1.3%. Without knowing how to interpret this difference, and because it is relatively small, the Reference case forecast is used for the industrial sector. Figure 3-1 illustrates the updated *AEO2012* baseline forecast used in this study, and the original Reference case forecast.

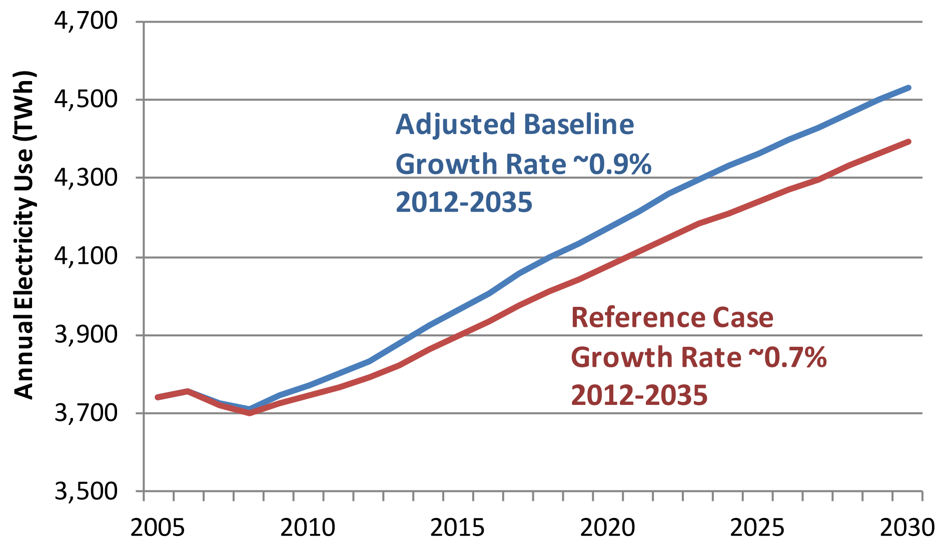

Figure 3-1
Adjusted Baseline Forecast and the AEO2012 Reference Case

2012 Electricity Use and Peak Demand

This study characterizes three dimensions of electricity use: annual electrical energy consumption, summer coincident peak demand and winter coincident peak demand.

2012 Annual Electricity Use

Based on the *AEO2012* baseline, annual electricity use for the U.S. is estimated at 3,724 TWh. This represents 11.8 MWh per capita and 0.28 kWh per dollar of Gross Domestic Product in 2012. The allocation of U.S. electricity use across sectors is fairly even. As shown in Figure 3-2, the residential sector accounts for 38%, the commercial sector accounts for 36%, and the industrial sector uses 26%.

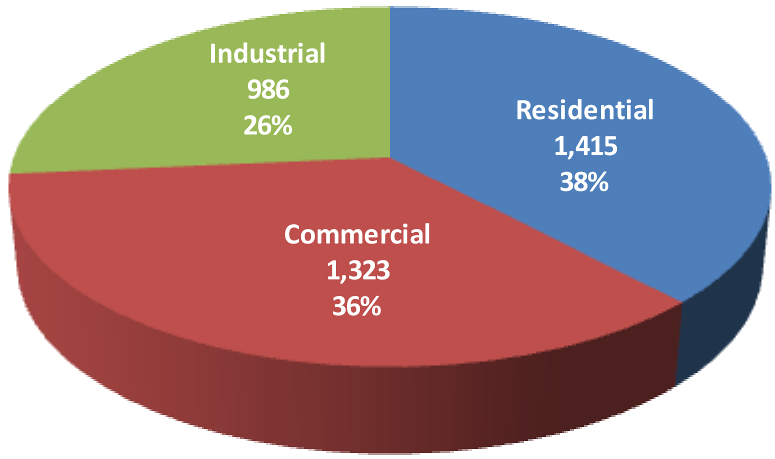

Figure 3-2
U.S. Annual Electricity Use by Sector in 2012

Table 3-1 presents 2012 electricity use by region and sector from the *AEO2012* baseline. The South Census division is the largest region with 45% of the total, followed by West at 23%, the Midwest is 18%, followed by the Northeast with 13%.

In the Northeast and West census regions, the commercial sector is the largest whereas the residential sector is largest in the South. The industrial and residential sectors have equal shares in the Midwest. The industrial sector has the smallest share across all other regions. In the Midwest, the sectors have almost equal shares, while the other regions show greater variation among sector splits.

Table 3-1
2012 Electricity Use by Sector and Region

	Northeast	South	Midwest	West	U.S.
2012 Electricity Use (TWh)					
Residential	182	690	295	248	1,415
Commercial	209	577	274	264	1,323
Industrial	97	434	293	161	986
Total	**488**	**1,701**	**862**	**672**	**3,724**
% of U.S.	13%	46%	23%	18%	100%
Sector Share of Region					
Residential	37%	41%	34%	37%	38%
Commercial	43%	34%	32%	39%	36%
Industrial	20%	26%	34%	24%	26%
Total	**100%**	**100%**	**100%**	**100%**	**100%**

Note: Numbers in table may not sum to the total due to rounding.

Figure 3-3 gives a closer look at the divisions which constitute the Census regions. The highest consumption of electricity is in the East North Central division, which happens to fall in the Midwest Census region, whereas the lowest is in Mountain North division, within the West Census region.

In general, residential sector electricity consumption is on par with commercial in all divisions similar to the national level. In all divisions except the East North Central and East South Central industrial has the lowest share of electricity consumption. However in these two divisions the share of industrial is the largest of all the sectors.

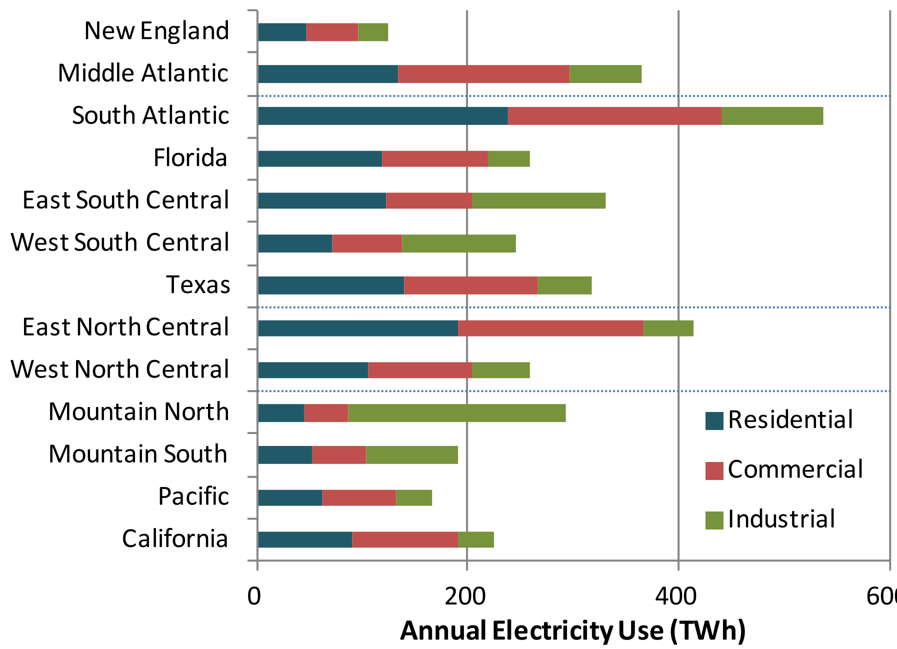

Figure 3-3
2012 Annual Electricity Use by Sector and Division

Residential Sector

In 2012, annual electricity use in the residential sector was 1,415 TWh or 38% of the total across sectors. Figure 3-4 shows the breakout by end use from the *AEO2012*. Note that primary electric space heating *not* provided by a heat pump is captured in the non-heat pump (non-HP) electric heat category, e.g., resistance strip heat.

- The largest end-use category was other uses, 21% of residential consumption in 2012. This includes miscellaneous end uses such as non-TV and non-PC consumer electronics, small appliances, small motors, battery chargers, etc. In the future we hope to discern more end uses from this category as this Annual Energy Outlook category is further segmented beginning with *AEO2014*.
- The highest consumption by a single end-use equipment in 2012 was central air conditioning (central AC) (220 TWh), which accounted for 16% of total annual use. The second largest was lighting (191 TWh), accounting for 13% of the

annual total. Since 2005 there was been a reduction of electricity consumption by lighting by about 12% from 217 TWh.

- Water heating accounted for 9% of residential electricity in 2012, at 134 TWh which is about an 8% increase from 124 TWh consumed in 2005. Refrigerators consumed 8% at 109 TWh, which is down by 6% from what was consumed by refrigerators in 2005.
- Televisions accounted for 5% of total electricity consumed in 2012, an 8% increase from 2005.

For all of the isolated end uses, specific energy efficiency measures have been evaluated and savings have been quantified (as described in Section 2). For the Other Uses end-use category, this study does not project energy-efficiency savings through utility programs due to the lack of granularity.

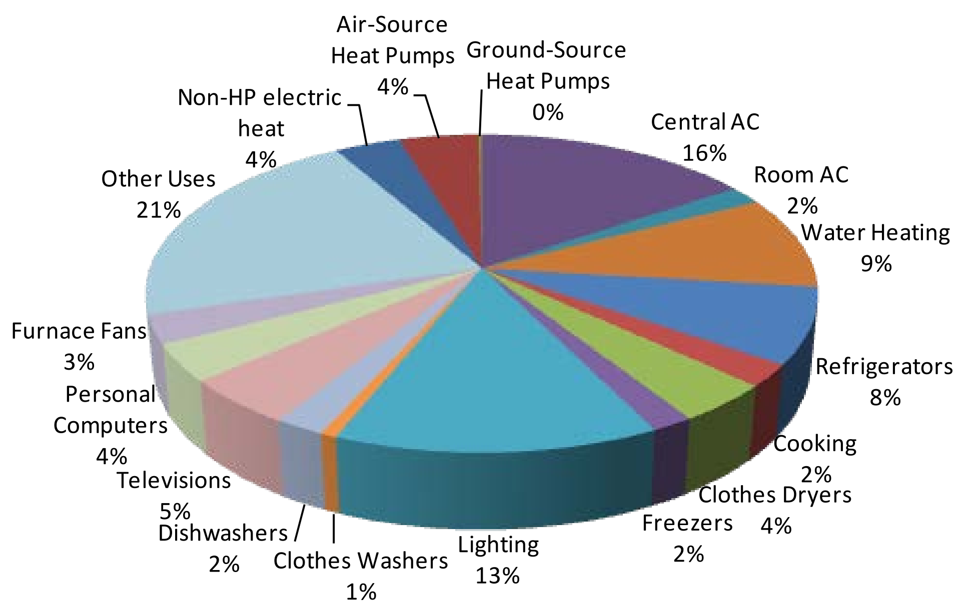

Figure 3-4
2012 U.S. Residential Electricity Use by End Use

Figure 3-5 shows the residential end-use consumption per household by division. The appliances category captures refrigerators, freezers, cooking, clothes washers and dryers and dishwashers. Space cooling includes central AC and room AC for primary space cooling. Heat pumps include both primary space heating and cooling within a home. All other primary space heating is captured in non-HP electric heating.

Florida and the South Atlantic division have a larger share of electricity consumption by heat pumps (providing both heating and cooling): 20% and 39% of 2012 U.S. heat pump consumption respectively. The South Atlantic division and Texas have the highest share of space cooling consumption at 18% and 16% of the total respectively. Together the five divisions comprising the South Census region (South Atlantic, Florida, East South Central, West South Central, and Texas) account for 64% of electric space heating and cooling consumption in the U.S. in 2012.

There is a much higher saturation of electric heating in the South Census region in part due to the relatively milder climate. This is compared to the Northeast and Midwest divisions (New England, Middle Atlantic, East North Central and West North Central) where there is very little electric heating and heat pump consumption.

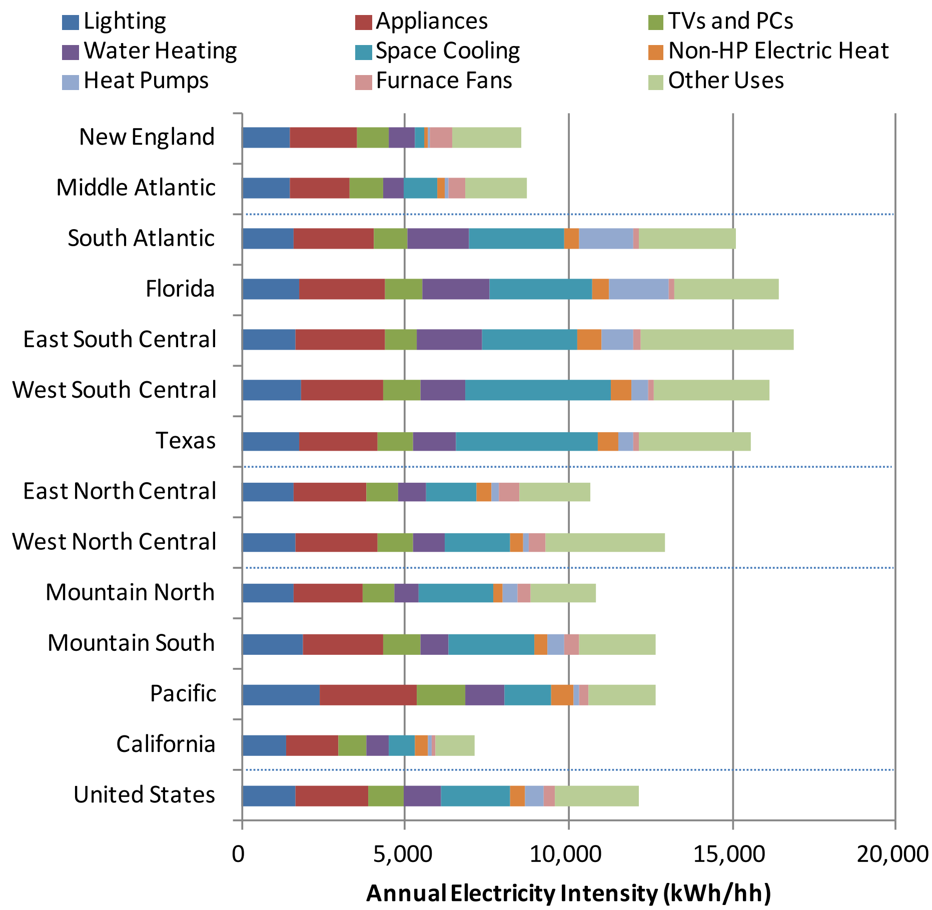

Figure 3-5
U.S. Residential End Use Consumption per Household by Division

In many divisions the other uses category had the highest per household consumption in 2012. This category encompasses myriad miscellaneous end uses from hair dryers to pool pumps. Due to the diverse nature of the equipment captured in this category and a lack of details it is difficult to say what contributes to differences in other uses between divisions. The rest of the end use categories presented in Figure 3-5 represent distinct technology categories and the following discussion looks at these end use categories in each Census region.

The Northeast Census Region

The Northeast (New England and Middle Atlantic) had some of the lowest electricity use per household in 2012, with New England at 8,540 kWh and Middle Atlantic at 8,699 kWh per household per year. This reflects low air conditioning use as a result of a shorter cooling season and a lower saturation of air conditioners. New

England also has the lowest per household use of heat pumps and non-heat pump electric heating consumption, pointing to the prevalence of other fuels used for heating

The South Census Region

The use per household is highest in the South region (South Atlantic, Florida, East South Central, West South Central, and Texas), with the highest being in the East South Central division at 16,870 kWh per household per year. Barring the other uses category, the largest use of electricity in the South was for space cooling, followed by household appliances. The South Atlantic division and Florida had the highest share of heat pump consumption at 11%, as compared to other divisions.

The Midwest Census Region

In the Midwest, appliances were the largest end use category, followed by lighting in the East North Central division and space cooling in the West North Central division. Similar to the Northeast, there is little heat pump consumption and space cooling is lower than in the South Census region and the Mountain divisions.

The West Census Region

In the West, California used the lowest amount of electricity per year per household (7,107 kWh) among all the divisions. As with the Northeast and Midwest Census regions, appliances is the dominant end use in the Pacific division and California, followed by lighting. In general, the summers and winters in the West are milder compared to the other regions.

Commercial Sector

In 2012, annual electricity use in the commercial sector was 1,323 TWh or 36% of the total across sectors. Figure 3-6 shows the breakout by end use.

- 409 TWh, or 31% was consumed by other uses which includes miscellaneous end uses not captured in the other major equipment categories.
- The largest single end use was lighting (294 TWh), accounting for 22% of total annual use. This is a reduction from 27% of consumption in 2005.
- Lighting is followed by ventilation at 12% and cooling at 10%. While cooling was about the same in 2005 at 12%, the share of ventilation was only 4% in 2005.
- Electric water heating is the smallest single end-use of commercial electricity identified by the AEO at 2%.

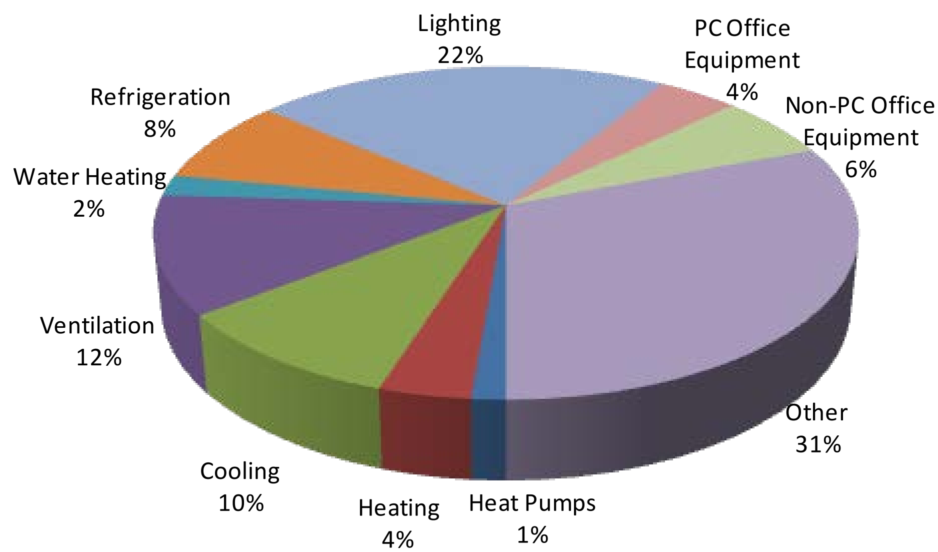

Figure 3-6
2012 U.S. Commercial Electricity Use by End Use

Figure 3-7 shows the commercial end-use consumption per square foot by division.

Together the five divisions comprising the South Census region (South Atlantic, Florida, East South Central, West South Central, and Texas) account for 64% of electric space cooling alone, and 55% of electric heating and cooling consumption in the U.S. in 2012. Heating, ventilation and air conditioning (HVAC) accounts for at least 19% of 2012 electricity consumption in all divisions, and a full third of consumption in the West South Central and Texas. Heat pump consumption for space heating and cooling accounts for less than 10% of HVAC consumption in each of the divisions.

For the most part lighting is about 19-24% of electricity in all divisions except in the East North Central where lighting is 27% of electric consumption.

Where other fuels are available such as natural gas space heating and water heating, electricity is a relatively small share of energy consumption.

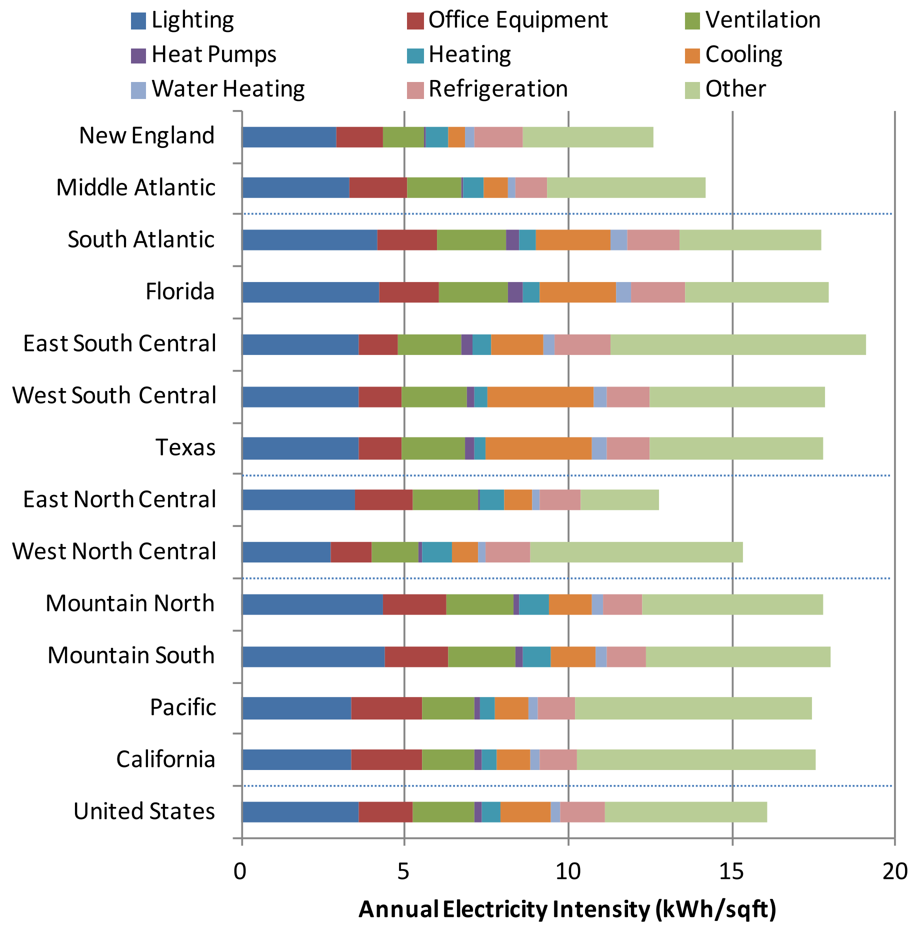

Figure 3-7
2012 U.S. Commercial Intensity by Division

The Northeast Census Region

Along with the Midwest, the Northeast has low saturation of water heating and heat pumps, due to preference for other fuels in these end-use categories. The New England Census division has the highest share of refrigeration at 12%, all other divisions are below 10%.

The South Census Region

The South has a higher share of electric heating (not from a heat pump), although still less than three percent. About 14% of electricity in the South is consumed for space cooling, compared to less than 7% in other divisions. The South also has the highest share of overall HVAC at 30% of electricity compared to between 21% and 26% in the other divisions.

The Midwest Census Region

The East North Central division stands out as having a higher share of indoor lighting and ventilation than other divisions. Refrigeration is highest in the Midwest region overall with about 9% of total electricity.

The West Census Region

The West also has a higher share of electric heating (not from a heat pump) compared to the other regions although still only a little over one percent. Refrigeration is lowest in the West region with about 6% of total electricity.

Industrial Sector

In 2012, annual electricity use in the industrial sector was 986 TWh or 26% of the total across sectors. Figure 3-8 shows the breakout of industrial electricity consumption by manufacturing segment (note that the 3-digit NAICS code(s) is shown with the percent share of the total in the pie chart). The 3-digit NAICS code(s) covered by each segment along with the manufacturing category are shown in the legend to the right. Chemicals and allied products (NAICS 325) have the largest share of industrial consumption and furniture (NAICS 337) has the lowest share. In all the range of consumption is fairly even with no segment having a clear majority of the consumption.

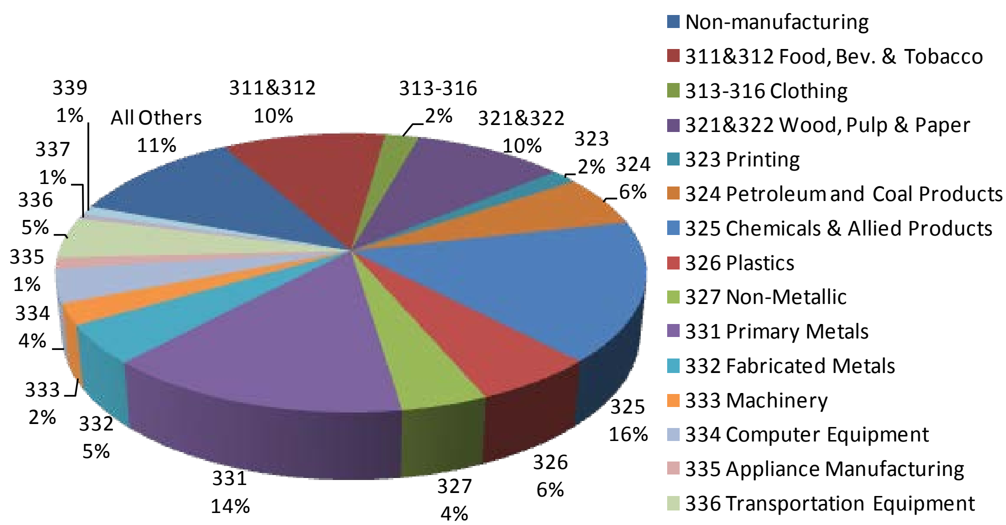

Figure 3-8
2012 U.S. Industrial Electricity by Manufacturing Segment

Figure 3-9 shows the breakout of industrial consumption by manufacturing process. Non-manufacturing industrial usage, about 11% of industrial consumption is not treated in this study. The industrial facilities category includes office uses such as air conditioning, lighting, etc.

- The largest identifiable process is industrial facilities (166 TWh), accounting for 17% of total annual use. This includes office uses such as air conditioning, lighting, etc.
- This is followed by electrochemical processes at 12%, and process heating and cooling at 10%.
- Compared to the residential and commercial sectors, the "other" category comprises a relatively low share of industrial electricity, 10%.

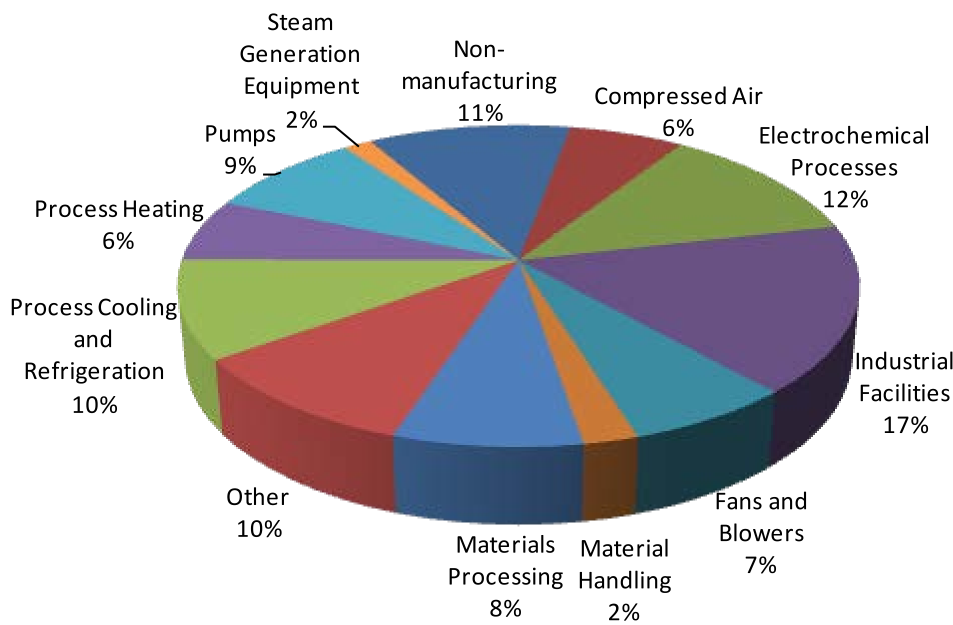

Figure 3-9
2012 U.S. Industrial Electricity by Process

Industrial consumption broken out by process for each division is shown in Figure 3-10. The East North Central has the highest share of industrial electricity consumption (21%) of all industrial electricity consumption, the New England and Mountain North divisions have the lowest shares, about 3% each.

In all divisions except the East North Central and West North Central, electrochemical processes have the largest share of industrial consumption. In the Midwest division (East North Central and West North Central), process heating and cooling have the largest share of consumption. Steam generation has the lowest share, between 1% and 2% in all divisions. Otherwise electricity consumption by process is fairly evenly spread out in each division with no single end use representing a clear majority of consumption.

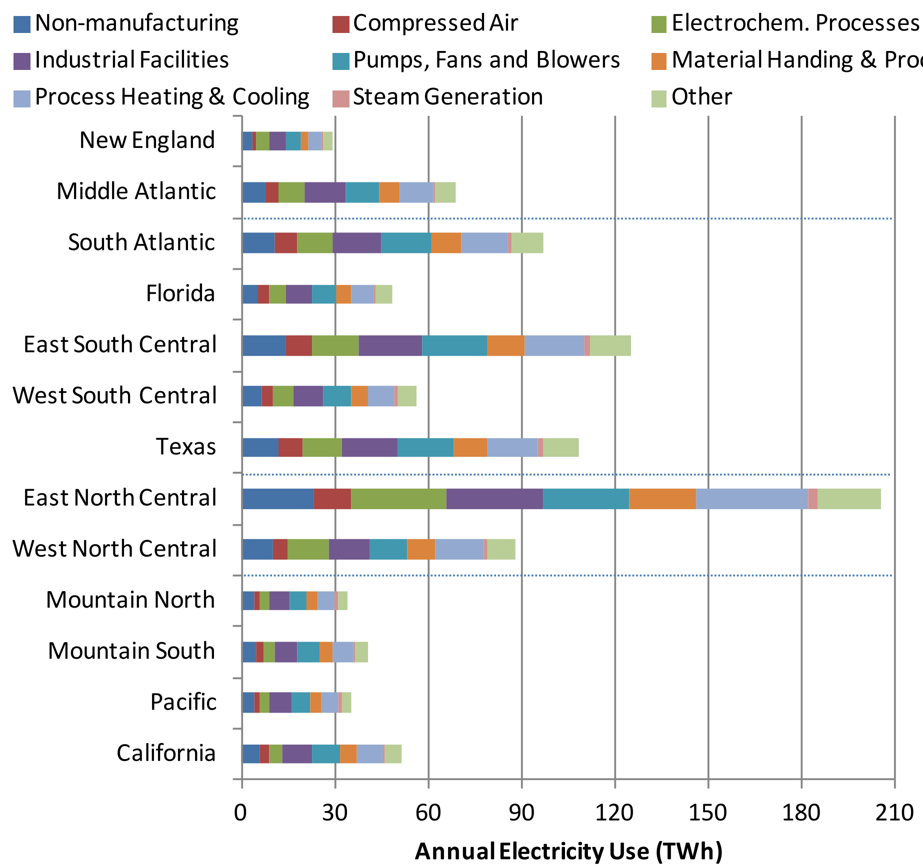

Figure 3-10
2012 U.S. Industrial Electricity Use by Process and Division

Table 3-2 shows the process shares for industrial consumption by Census region which correspond to the break out of industrial consumption in Figure 3-10.

Table 3-2
Industrial Process Shares by Census Region

	Northeast	South	Midwest	West
Non-manufacturing	11.2%	11.2%	11.2%	11.2%
Compressed Air	5.8%	6.9%	6.1%	5.7%
Electrochem. Processes	12.5%	11.8%	14.7%	8.7%
Industrial Facilities	19.4%	16.6%	15.2%	19.1%
Pumps, Fans and Blowers	15.9%	16.4%	13.5%	17.0%
Material Handing & Proc.	9.3%	9.9%	10.3%	10.0%
Process Heating & Cooling	15.3%	15.2%	17.6%	16.6%
Steam Generation	1.3%	1.5%	1.6%	2.0%
Other	9.3%	10.5%	9.9%	9.7%

Note: Numbers in table may not sum to the total due to rounding.

2012 Coincident Peak Demand

Coincident demand is calculated at the end-use level using load factors and coincidence factors. Both summer and winter peak coincident demand are evaluated for each sector, using the system peak periods defined in Table 3-3. It is assumed that the load and coincidence factors for industrial are the same for summer and winter and therefore the demand forecasts are the same for both.

Table 3-3
Summer and Winter Coincident Peak Definitions

	Summer	Winter
Months	June, July, August, September	December, January, February, March
Days	Monday - Friday	Monday - Friday
Hours	Hours ending 16-20	Hours ending 6-11

The 2012 summer and coincident demand corresponding to the 2012 annual energy use presented earlier in the section is broken down by sector in Figure 3-11. In both summer and winter residential has the largest share of system coincident demand, in fact residential HVAC and water heating drive system peak demand.

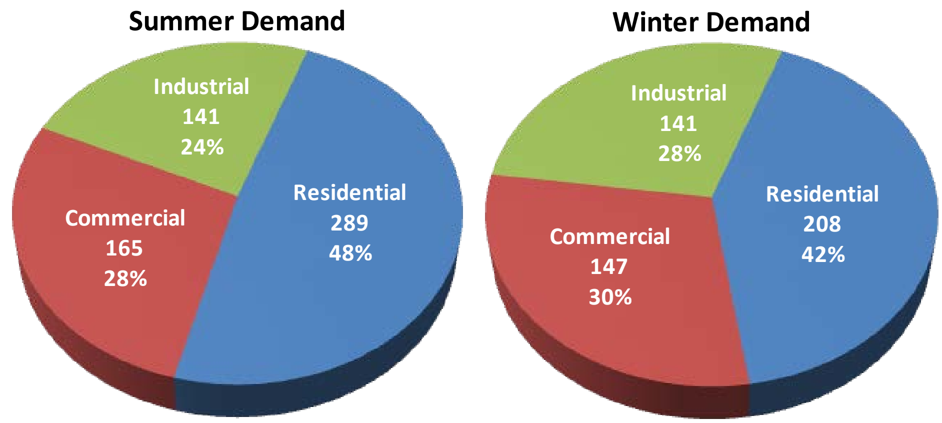

Figure 3-11
U.S. 2012 Summer and Winter Coincident Peak Demand by Sector (GW)

The relative shares of sector-level seasonal peak demand differ somewhat by Census region, shown in Table 3-4. The Census region shares of both summer and winter demand are nearly the same as the shares of energy in each region.

Overall the residential sector has the highest share of both winter and summer peak demand in each Census region. This reflects the fact that residential loads such as cooling and water heating typically drive the system peak.

Table 3-4
2012 Summer and Winter Coincident Peak Demand by Sector and Region

	Northeast	South	Midwest	West	U.S.
2012 Summer Coincident Peak Demand (GW)					
Summer (GW)	75	281	136	102	595
% of U.S.	13%	47%	23%	17%	100%
Sector Share of Region, Summer					
Residential	49%	51%	46%	46%	49%
Commercial	32%	27%	24%	32%	28%
Industrial	18%	22%	31%	22%	24%
Total	**100%**	**100%**	**100%**	**100%**	**100%**
2012 Winter Coincident Peak Demand (GW)					
Winter (GW)	69	215	124	88	495
% of U.S.	14%	43%	25%	18%	100%
Sector Share of Region, Winter					
Residential	43%	44%	39%	39%	42%
Commercial	36%	27%	27%	35%	30%
Industrial	20%	29%	34%	26%	28%
Total	**100%**	**100%**	**100%**	**100%**	**100%**

Note: Numbers in table may not sum to the total due to rounding.

2012 Residential Peak Demand

Residential peak demand is largely driven by space cooling and water heating. Lighting has little contribution to residential summer or winter peak load. Peak demand intensity for TVs and PCs, appliances and other uses total is nearly the same in each division summer to winter, differing by only a few percent.

Figure 3-12 shows residential summer coincident peak demand for 2012. This is shown by division, and is broken out by end use.

HVAC accounts for between 39% and 63% of coincident summer demand intensity in all divisions, 51% for the U.S. on average. Over 50% of household coincident demand is HVAC in Mountain divisions, Florida, West South Central, Texas and East North Central divisions. With water heating included, the weather-dependent load comprise between 46% and 68% of summer demand intensity. Water heating alone is between 4% and 8%.

Heat pumps (providing space cooling) have a noticeable contribution to summer peak in the South divisions and the Mountain divisions. Elsewhere they contribute about a percent or less to household summer peak demand.

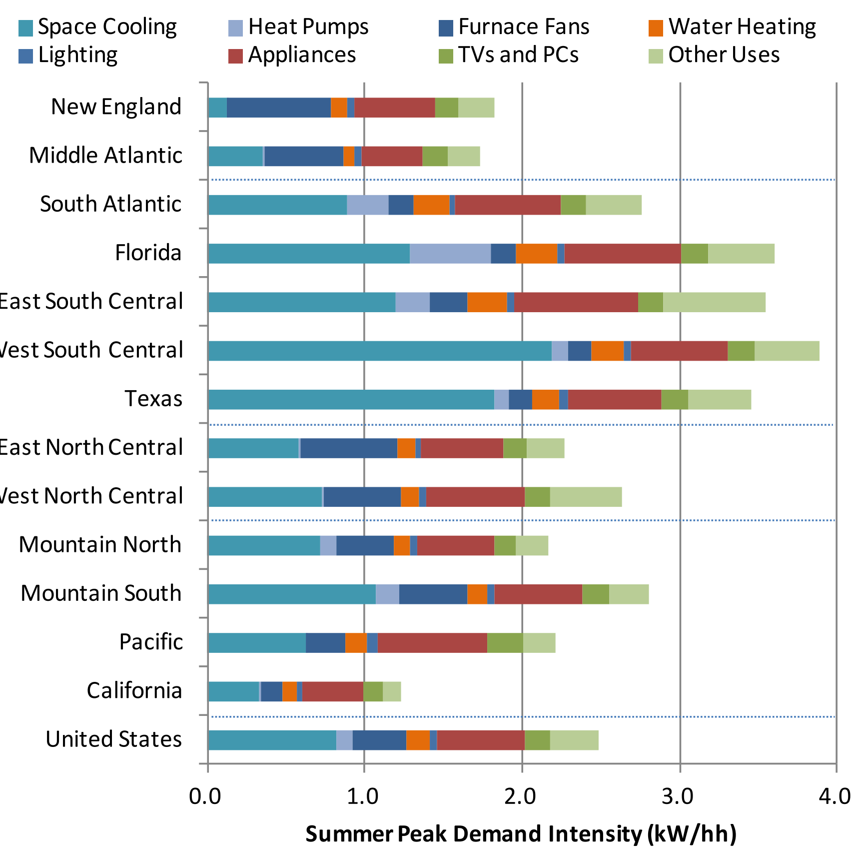

Figure 3-12
2012 U.S. Residential Summer Coincident Peak Demand Intensity, kW per Household by Division

Figure 3-13 shows residential winter coincident peak demand for 2012. This is shown by division, and is broken out by end use.

HVAC contributes between 15% and 38% to winter peak demand intensity, 28% for U.S. Florida, Texas and West South Central HVAC is less than 20% of winter peak demand. Including water heating, weather-dependent loads account for between 30% and 46% of coincident demand per household through the U.S. Water heating alone between 8 and 18% of winter peak, it is a stronger driver for winter peak than summer peak because usage for morning showers coincides with morning electric heating load.

Heat pump contribution to winter peak is higher than summer peak, most notably in the South Atlantic division. Aside from the South Atlantic, heat pump heating is less than 10% of household winter coincident demand.

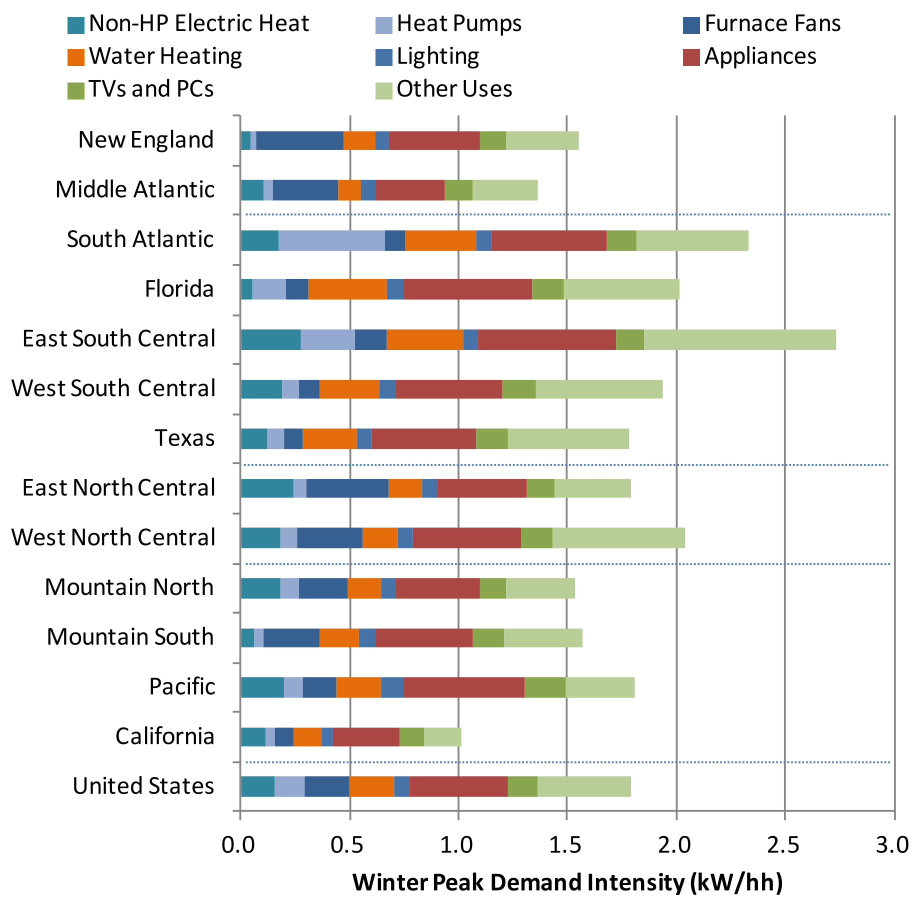

Figure 3-13
2012 U.S. Residential Winter Coincident Peak Demand Intensity, kW per Household by Division

2012 Commercial Peak Demand

HVAC is a major contributor to commercial coincident peak demand. Lighting has a significant share of peak demand compared to the residential sector. Peak demand intensity for office equipment, and other uses is very similar in each division summer to winter, differing by only a few percent.

Figure 3-14 shows commercial summer coincident peak demand for 2012. This is shown by division and is broken out by end use.

Lighting is a bigger contributor to coincident peak demand in the summer and winter in the commercial sector than in the residential sector. Between 16% and 23% of summer demand per square foot, and between 14% and 24% of winter demand per square foot.

HVAC contributes between 19% and 42% to summer coincident peak intensity. Including water heating, the share of weather-sensitive end-uses increases to 21% to 44% of peak. Water heating has little contribution to coincident peak per square foot in the summer.

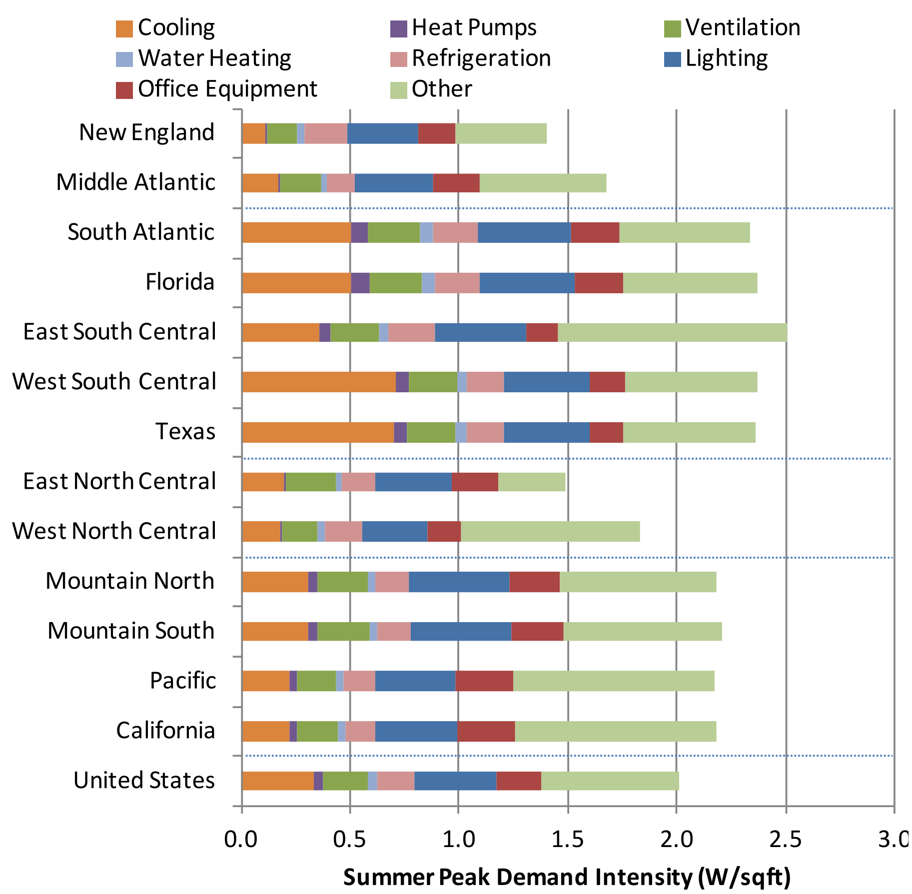

Figure 3-14
2012 U.S. Commercial Summer Coincident Peak Demand Intensity, W per Square Foot by Division

Figure 3-15 shows commercial summer coincident peak demand for 2012. This is shown by division and is broken out by end use.

HVAC contributes between 19% and 36% of coincident winter peak demand intensity across the divisions. Including water heating in the weather-sensitive measures this increases only a couple percent. Commercial water heating is not a significant driver of summer and winter system coincident peak.

Coincident demand for lighting is slightly lower in the winter than in the summer.

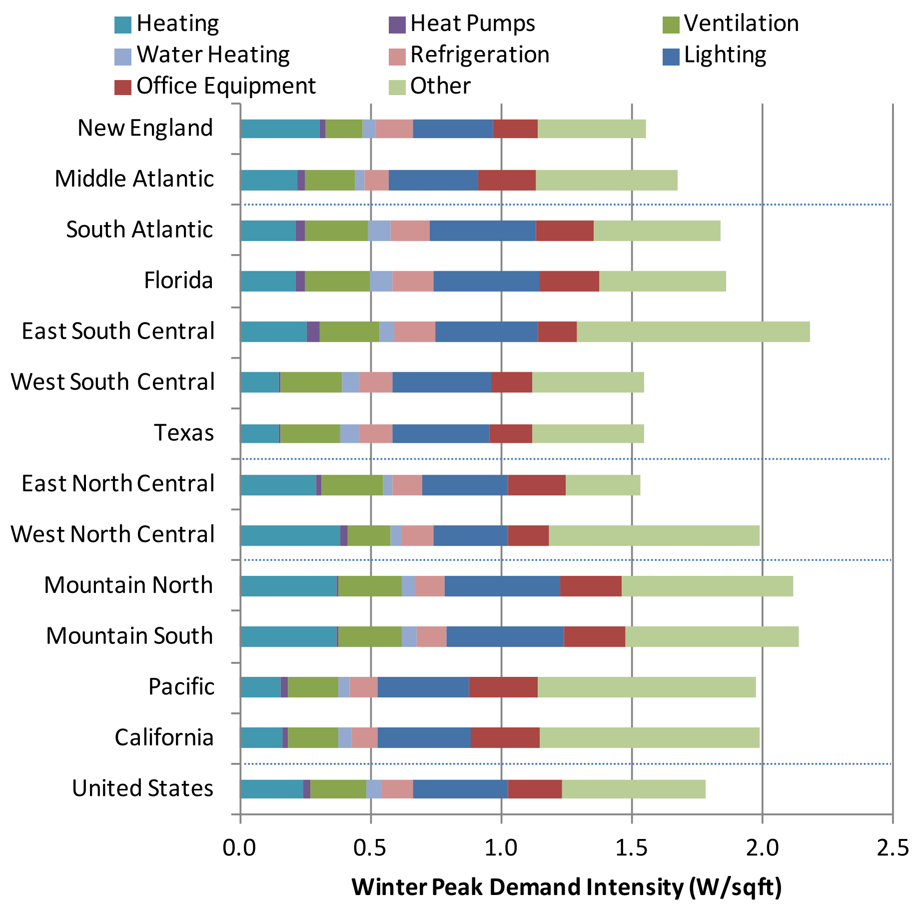

Figure 3-15
2012 U.S. Commercial Winter Coincident Peak Demand Intensity, W per Square Foot by Division

2012 Industrial Peak Demand

Figure 3-16 shows industrial coincident peak demand by division, broken out by industrial process. Industrial coincident demand is the same for both summer and winter.

Similarly to 2012 energy consumption by process, in all divisions except the East North Central and West North Central, electrochemical processes are the biggest contributor to industrial coincident peak. In the Midwest division (East North Central and West North Central), process heating and cooling have the largest share of coincident demand. Steam generation has the lowest share of coincident peak, between 1% and 2% in all divisions.

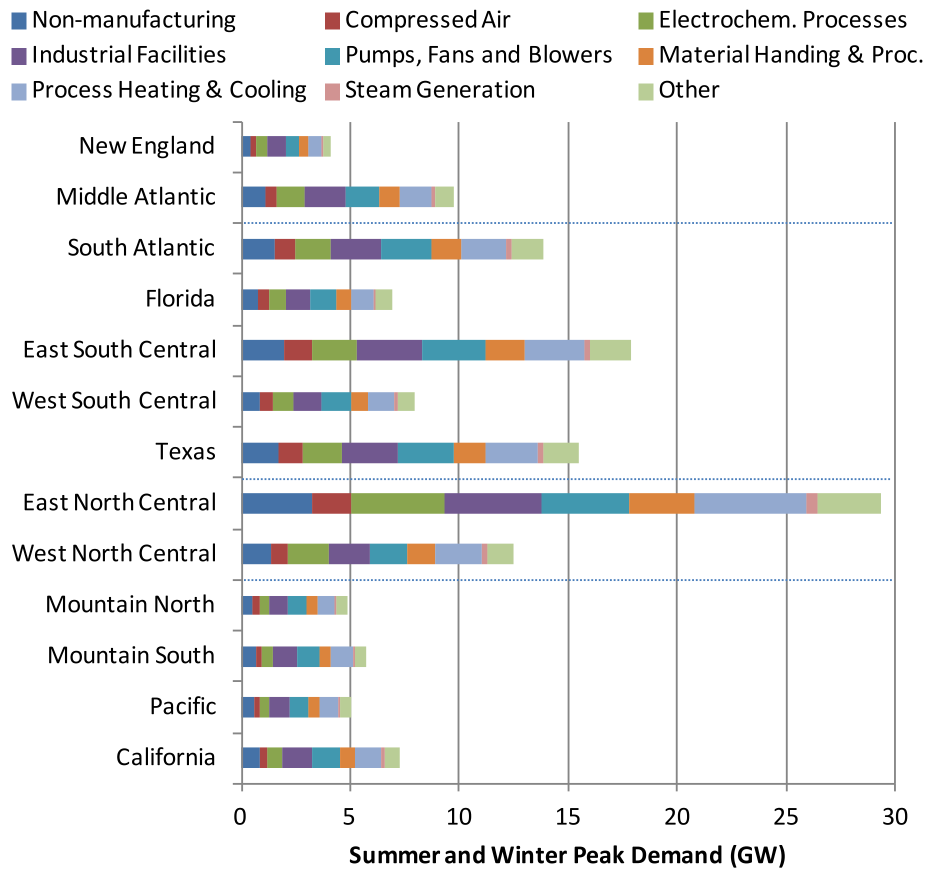

Figure 3-16
2012 U.S. Industrial Coincident Peak Demand, by Division and Process

The Baseline Forecast

Baseline forecasts for electricity consumption and summer and winter coincident peak demand are presented in the following section. The electricity use forecast is based on the *AEO2012* Reference case and the *AEO2012* 2011 Demand Technology case. The Reference case includes some level of assumed energy efficiency adoption which may be naturally occurring, resulting from efficiency programs, or due to technology innovation. The 2011 Demand Technology case freezes technology options at the 2011 level and thus strips out the impacts of the assumed efficiency in the Reference case. The forecasts used in this analysis add the assumed impacts of energy efficiency achieved through efficiency programs and technology innovation to avoid double counting of efficiency impacts.

Forecast of Annual Electricity Use

The adjusted AEO2012 baseline including retail sales for 2005-2012 is shown in Figure 3-17. Electricity consumption in the residential, commercial and industrial sectors saw modest growth between 2005 and 2012 (0.3% CAGR). Looking at the changes between 2007 and 2014, the *AEO2012* shows a near zero CAGR. Digging into the data, in 2008 and 2009 electricity use declined by 0.8% and 3.7% respectively compared to the previous year. By 2011 consumption returned to 2007 levels. Consumption dropped again in 2012 from 2011, and the *AEO2012* forecasts that 2013 consumption will be lower than 2012. Several factors may be contributing to these net-zero changes including the economy, household formation trends, and weather.

On average, growth is expected between 2012 and 2035, with the AEO estimating 0.9% annual growth between 2012 and 2035.

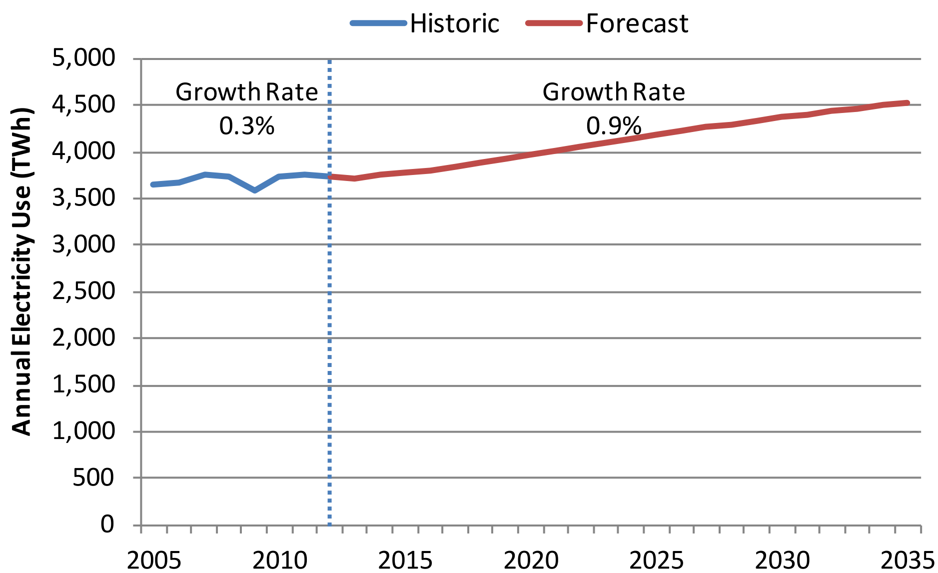

Figure 3-17
U.S. Electricity Historical Consumption and Forecast

Figure 3-18 shows the breakout of annual consumption by Census region for key years throughout the forecast. The South Census region accounts for over 45% of total U.S. electricity consumption over the forecast period. Both the South and West Census regions are forecast to increase consumption by about 30% from 2012 to 2035. Forecast growth from 2012 to 2035 for the Northeast and Midwest Census regions is more moderate with 5% and 10% total respectively.

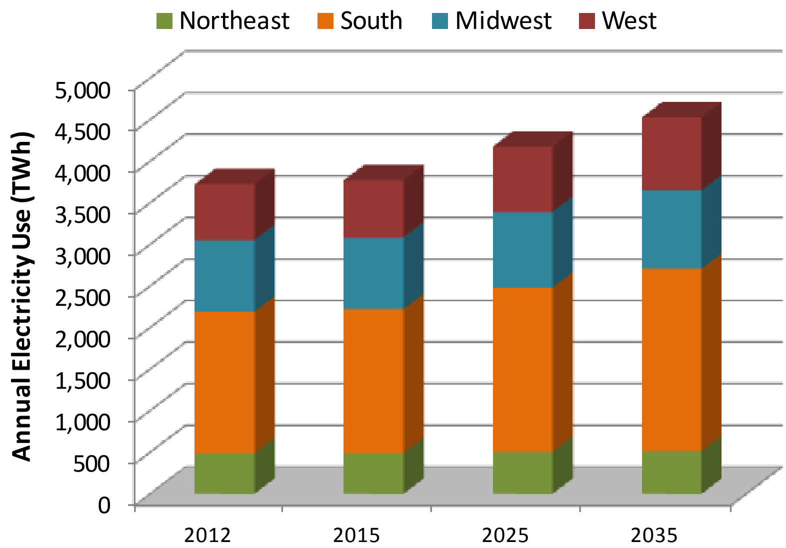

Figure 3-18
U.S. Electricity Forecast by Census Region

Forecast electricity consumption is further broken out by division in Table 3-5. Within each region there is one division that clearly has higher consumption than the other division(s). Interestingly in the West, the state of California consumes more than the other divisions. Overall the three large states included in the analysis, California, Texas and Florida, account for about 25% of U.S. electricity consumption over the forecast period.

The AEO forecast predicts modest annual growth of less than a percent in the Northeast and Midwest divisions. The South and West divisions are expected to have higher annual growth, some greater than one percent.

Table 3-5
U.S. Electricity Forecast by Division (TWh)

	2012	2015	2025	2035	% Change (2012-2035)	CAGR (2012-2035)
Northeast Census Region						
New England	124	124	129	129	4%	0.2%
Middle Atlantic	364	365	380	385	6%	0.2%
South Census Region						
South Atlantic	536	547	636	721	34%	1.3%
Florida	267	273	317	359	34%	1.3%
East South Central	330	336	376	407	24%	0.9%
West South Central	193	196	219	240	24%	0.9%
Texas	375	379	424	464	24%	0.9%
Midwest Census Region						
West North Central	572	573	598	616	8%	0.3%
East North Central	291	291	313	331	14%	0.6%
West Census Region						
Mountain North	121	125	146	166	37%	1.4%
Mountain South	144	148	174	197	37%	1.4%
Pacific	167	170	190	210	26%	1.0%
California	241	246	275	304	26%	1.0%
Total U.S.	**3,724**	**3,773**	**4,177**	**4,529**	**22%**	**0.9%**

Note: Numbers in table may not sum to the total due to rounding.

Table 3-6 shows the adjusted AEO baseline broken out by sector over the forecast period along with the percent change from 2012 to 2035 and the CAGR over this period. The residential and commercial sectors are very close, with less than 10% difference. About 30% increase is expected in both the residential and commercial sectors, however industrial consumption is expected to be slightly lower than 2012 in 2035.

Table 3-6
U.S. Electricity Forecast by Sector (TWh)

	2012	2015	2025	2035	% Change (2012-2035)	CAGR (2012-2035)
Residential	1,415	1,410	1,592	1,805	28%	1.1%
Commercial	1,323	1,355	1,553	1,747	32%	1.2%
Industrial	986	1,008	1,032	977	-1%	-0.04%
Total	**3,724**	**3,773**	**4,177**	**4,529**	**22%**	**0.9%**

The sector shares of forecast consumption are illustrated in Figure 3-19. The relative mix of sector consumption remains relatively constant over the forecast with slight growth in residential and commercial shares and slight decline in industrial.

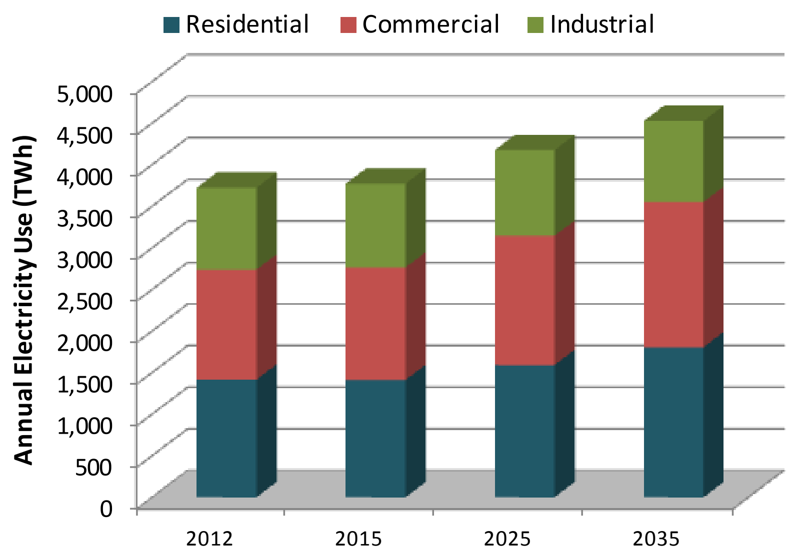

Figure 3-19
U.S. Electricity Forecast by Sector

The Residential Sector

Residential consumption is forecast to increase by 28% with a CAGR of 1.1% between 2012 and 2035. The U.S. total forecast consumption is shown in Table 3-7, broken out by housing segment. Moderate growth is forecast for single and mobile homes, with more than twice as much growth expected in the multi-family segment.

Table 3-7
U.S. Residential Electricity Forecast by Building Segment (TWh)

	2012	2015	2025	2035	% Change (2012-2035)	CAGR (2012-2035)
Mobile Homes	79	75	84	91	16%	0.6%
Single Family	1,112	1,105	1,227	1,375	24%	0.9%
Multi-Family	223	229	280	339	52%	1.8%
Total Residential	**1,415**	**1,410**	**1,592**	**1,805**	**28%**	**1.1%**

Note: Numbers in table may not sum to the total due to rounding.

The breakout by housing segment is illustrated in Figure 3-20. Consumption in single family homes accounts for over 75% of residential consumption over the forecast period. Mobile homes account for about 5% of total residential consumption. Although multi-family consumption is forecast to increase by 52% from 2012 to 2035, its share of total residential consumption only grows by a few percent from 16% in 2012 to 19% in 2035.

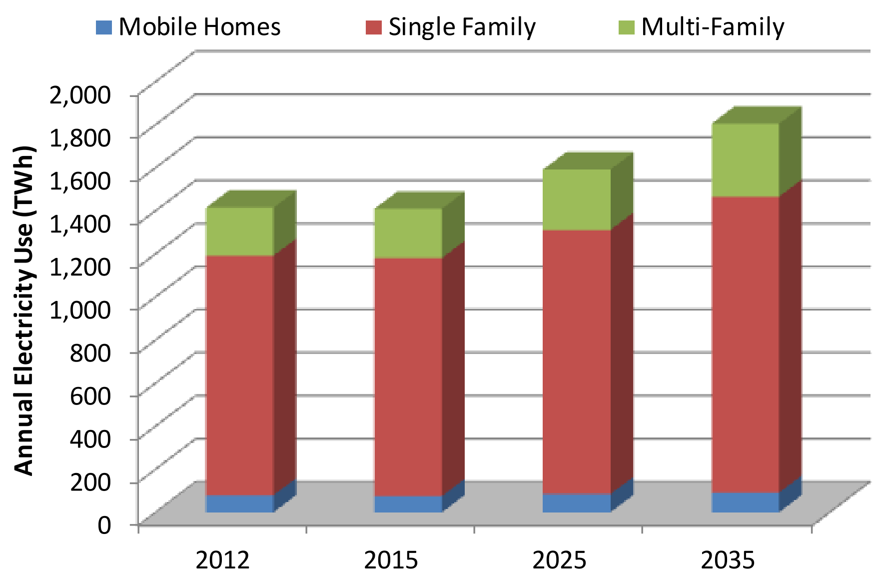

Figure 3-20
U.S. Residential Electricity Forecast by Building Segment

Overall residential electricity use is forecast to increase by 390 TWh from 2012 to 2035. The growth varies by end use including a forecast decrease in consumption for lighting, with a CAGR of -1.3%. This decrease is largely due to the Energy Information and Security Act of 2007 (EISA 2007) which requires more efficient lighting for several categories of general service lamps in 2012-2014. In 2020 a second round of EISA 2007 efficacy requirements comes into effect, requiring general service lamps to have an efficacy of 43 lumens of output per watt of input power. There are several technologies expected to meet these lighting efficacy requirements, all of which are included in the efficiency options for lighting in this analysis.

Residential lighting has a CAGR of -1.3% 2012-2035.

The impact of EISA 2007 will be a decline in screw-in lighting consumption, the primary light source in the residential sector. The introduction of efficient lighting technologies has changed shopping for lighting from equivalent watts to equivalent lumens. As we see innovative lighting technologies come to market we will shift from shopping for equivalent lumens to shopping for equivalent useful light output.

Relatively high growth is expected in end uses that have an alternative fuel option such as natural gas; specifically, heat pumps (space heating and cooling), cooking, and electric water heating, with forecast annual growth of 3.1%, 1.4% and 1.0% respectively. Improvements in heat pump technology will enable adoption of heat pumps where they may not have been feasible previously. Most notably heat pump consumption is forecast to increase by almost 6% annually in multi-family homes. The West South Central (including Texas) Census division and Mountain Census division have CAGRs of greater than 4% and the Northeast has a CAGR of 5.7% in the *AEO2012* baseline.

Miscellaneous end uses are forecast to have relatively high growth with 2.2% forecast for TVs plus PCs (electronics) and 2.1% for other uses. Non-TV or PC consumer electronics are currently captured in the other uses categories. With the adoption of tablet computing and smart phones over the past five years, evolution of consumer electronics in terms of technologies available to the customer, and the number purchased is expected in the future. There may be some shift from PC usage to other mobile technologies such as tablets and smart phones, or other technologies yet to be introduced. Currently it is difficult to predict growth in these categories, except to say that growth is expected.

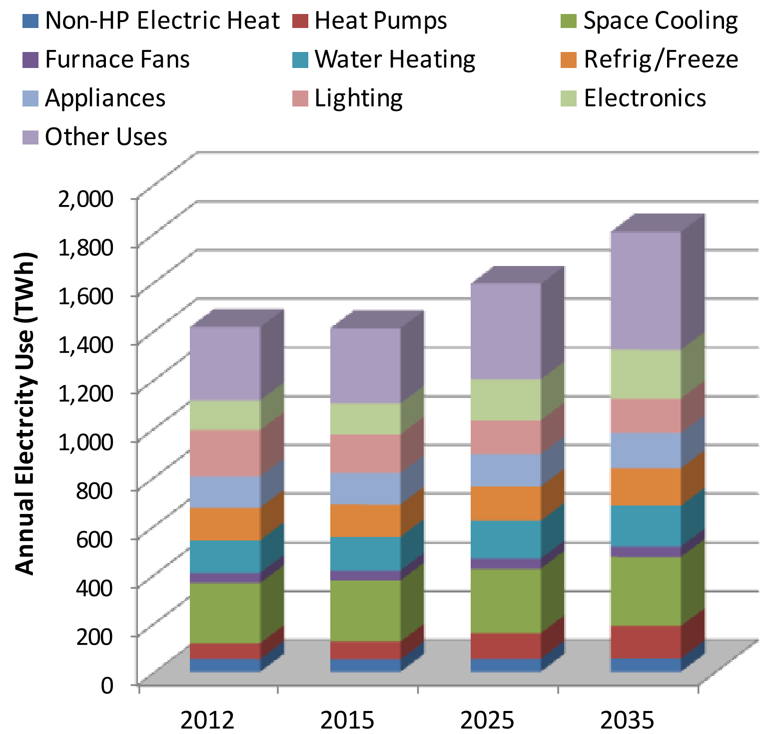

Figure 3-21
U.S. Residential Electricity Forecast by End Use

Residential Electric Intensity

Overall, residential electricity user per household, or intensity, is expected to increase with a CAGR of 0.1% from 2012 to 2035. In 2012 electricity use per house was 12,170 kWh, with a modest increase to 12,372 kWh per household forecast in 2035. Most end use categories see no change in intensity or a slight decrease in intensity from 2012 to 2035. Lighting, as expected has a relatively high decrease, of 2.2% annually. The exceptions are heat pumps, electronics and other uses which are expected to see growth in intensity over the forecast period.

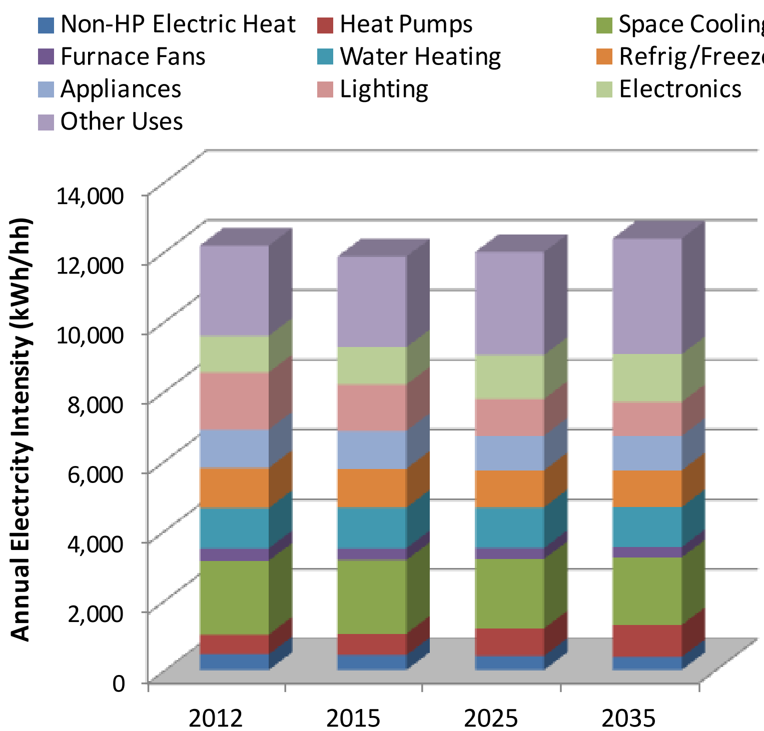

Figure 3-22
Forecast of U.S. Residential Electricity Use per Household

The Commercial Sector

Commercial consumption is forecast to increase by 32% with a CAGR of 1.2% between 2012 and 2035. The U.S. total forecast consumption is shown in Table 3-8, broken out by building type. Moderate growth is forecast for all building types. The highest growth is expected in large offices with 2.0% compound annual growth and the lowest growth is expected in education, wit 0.6% compound annual growth.

Table 3-8
U.S. Commercial Electricity Forecast by Building Segment (TWh)

	2012	2015	2025	2035	% Change (2012-2035)	CAGR (2012-2035)
Assembly	73	76	84	93	27%	1.0%
Education	130	134	142	150	15%	0.6%
Grocery	67	68	72	81	21%	0.8%
Restaurants	63	62	65	73	17%	0.7%
Health Care	59	63	71	76	29%	1.1%
Lodging	67	69	80	92	38%	1.4%
Large Office	152	158	189	238	56%	2.0%
Small Office	105	109	129	151	43%	1.6%
Retail	278	284	311	362	30%	1.2%
Warehouse	72	73	82	97	35%	1.3%
Other	70	74	85	103	46%	1.7%
Unspecified	186	185	242	232	24%	0.9%
Total Commercial	**1,323**	**1,355**	**1,553**	**1,747**	**32%**	**1.2%**

Note: The portion of the commercial building load that has no specified building type is captured under Unspecified, this is between 13-16% of commercial load over the forecast. Numbers in table may not sum to the total due to rounding.

Figure 3-23 shows the breakout of commercial electricity consumption by building type. Consumption in retail spaces accounts for about 20% of commercial consumption over the forecast period. The unspecified portion of the forecast is about 14% and represents electricity consumption where the building type is unknown.

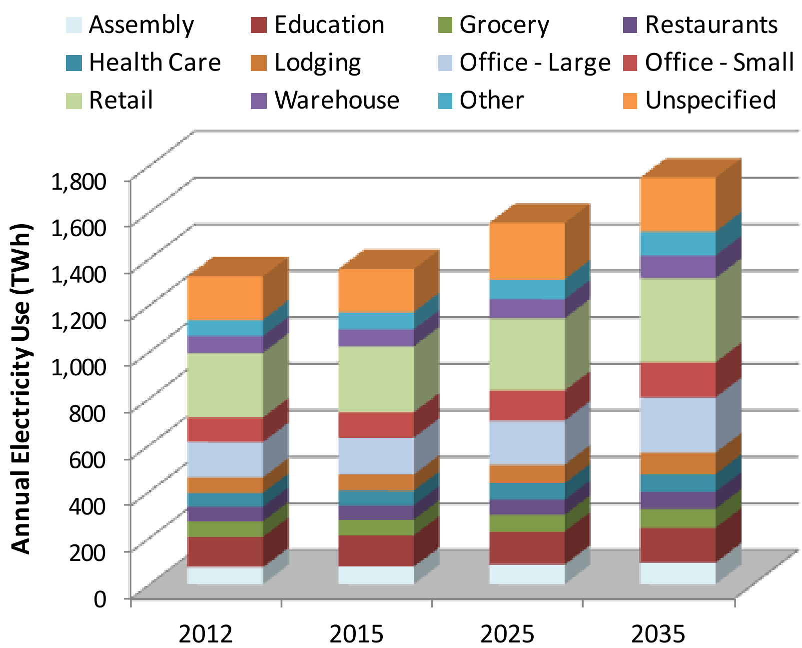

Figure 3-23
U.S. Commercial Electricity Forecast by Building Segment

Overall commercial electricity use is forecast to increase by 424 TWh from 2012 to 2035. The growth varies by end use including higher than average growth in office equipment and other uses, with 2.0% and 2.2% compound annual growth respectively. This reflects a similar trend in increased use of consumer electronics and communications in the commercial sector as well as residential. Connectivity and digitization are likely drivers for this trend.

The impact of EISA 2007 will be a decline in screw-in lighting consumption, which has less of an impact in the commercial sector where the primary lighting technology is linear fluorescent. As such, the potential for energy savings is still high in commercial lighting. In fact commercial lighting is forecast to have annual growth of 0.6%.

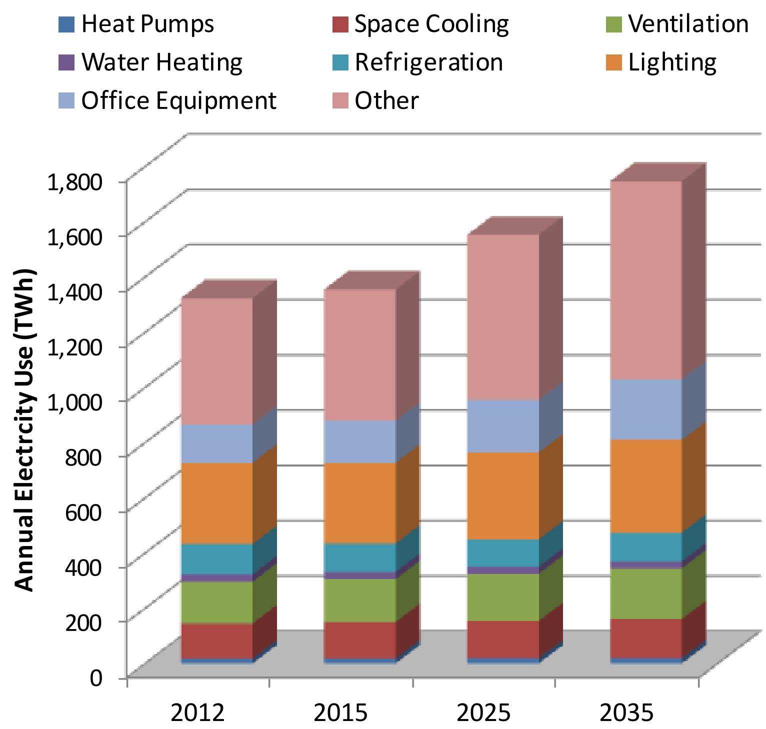

Figure 3-24
U.S. Commercial Electricity Forecast by End Use

Note: Other electric space heating not provided by heat pumps is captured in other.

Commercial Electric Intensity

Overall, commercial electricity user per square foot, or intensity, is expected to increase with a CAGR of 0.2% from 2012 to 2035. In 2012 electricity use per square foot was 16 kWh, with a modest increase to 17 kWh per square foot forecast in 2035. The forecast of intensity by end use is illustrated in Figure 3-25.

Office equipment and other uses are forecast to have 1.0% and 1.2% compound annual growth in intensity respectively, similarly to the forecast increases in total consumption.

All other end use categories are expected to have some decrease in intensity over the forecast period. Compared to the residential sector the CAGR for commercial lighting intensity is -0.4% (residential was -2.2%). The impacts of EISA 2007 are not as pronounced in the commercial sector due to the diversity in installed technologies. However although there is expected growth in total lighting consumption, increases in commercial floor space and assumed increases in efficiency outpace this growth resulting in a decline in lighting intensity.

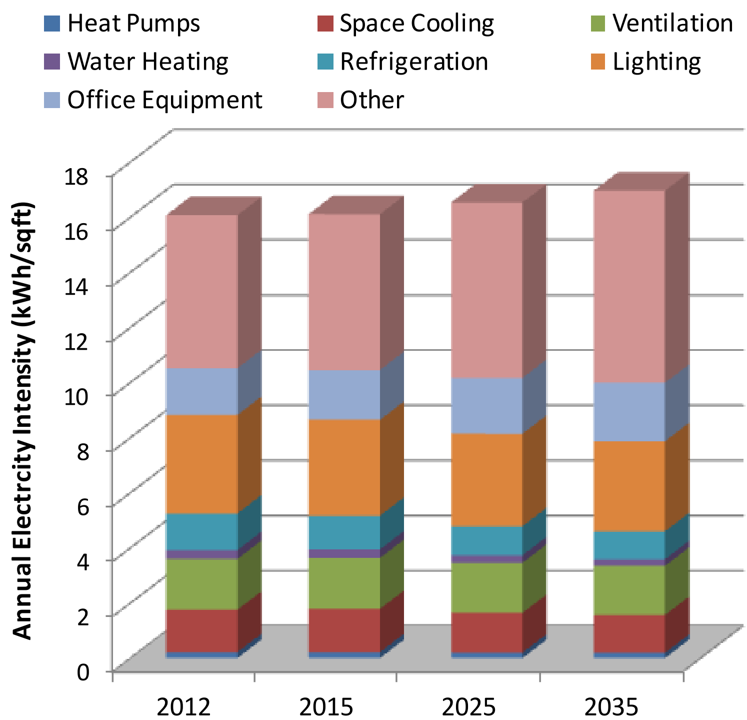

Figure 3-25
Forecast of U.S. Commercial Sector Electric Intensity

Note: Other electric space heating not provided by heat pumps is captured in other.

The Industrial Sector

2010 MECS data was used to split the manufacturing portion of the division-level industrial forecasts into manufacturing segments. The growth in the baseline forecast is applied to the manufacturing segments to find the NAICS-level forecasts for each division. This is further broken down to the process-level by NAICS code using data from DOE's Plant Energy Profiler (PEP) model.

Unlike commercial and residential, industrial consumption is forecast to decrease by 1% with a CAGR of -0.04% between 2012 and 2035. The U.S. total forecast consumption is shown in Table 3-9 broken out by manufacturing segment.

While non-manufacturing is forecast to increase by 21% between 2012 and 2035, manufacturing consumption is forecast to decrease by 4%. This may be due to changes in manufacturing located within the U.S., or this may indicate increased productivity for energy consumed (conversely decreased energy intensity).

Table 3-9
U.S. Industrial Electricity Forecast by NAICS Code (TWh)

	2012	2015	2025	2035	% Change (2012-2035)	CAGR (2012-2035)
Non-manufacturing	110	125	132	133	21%	0.8%
311&312 Food, Beverage & Tobacco	103	104	105	98	-5%	-0.2%
313-316 Clothing	21	22	22	22	2%	0.1%
321&322 Wood Products Pulp & Paper	95	96	99	94	-1%	-0.1%
323 Printing	16	16	17	15	-6%	-0.3%
324 Petroleum & Coal Products	58	59	61	58	-1%	-0.1%
325 Chemicals & Allied Products	160	162	166	156	-3%	-0.1%
326 Plastics	57	57	59	55	-2%	-0.1%
327 Non-Metallic	40	41	41	39	-4%	-0.2%
331 Primary Metals	142	143	145	135	-5%	-0.2%
332 Fabricated Metals	45	45	45	42	-6%	-0.3%
333 Machinery	24	24	24	22	-8%	-0.4%
334 Computer Equipment	38	38	39	37	-3%	-0.1%
335 Appliance Manufacturing	13	13	13	12	-5%	-0.2%
336 Transportation Equipment	47	47	48	44	-6%	-0.3%
337 Furniture	6	6	6	6	-5%	-0.2%
339 Miscellaneous Manufacturing	10	10	10	9	-5%	-0.2%
Total Industrial	**986**	**1,008**	**1,032**	**977**	**-1%**	**0.0%**

Note: Numbers in table may not sum to the total due to rounding.

Industrial electricity consumption by manufacturing segment is illustrated in Figure 3-26. Non-manufacturing accounts for 11% of industrial consumption in 2012, growing to 14% in 2035. Of the manufacturing segments, chemicals and allied products has the highest share (16%), followed by primary metals (14%), and food, beverage and tobacco, and wood products, paper and pulp both at 10% of industrial. The other manufacturing segments each represent less than 10% of industrial consumption in the U.S. as a whole.

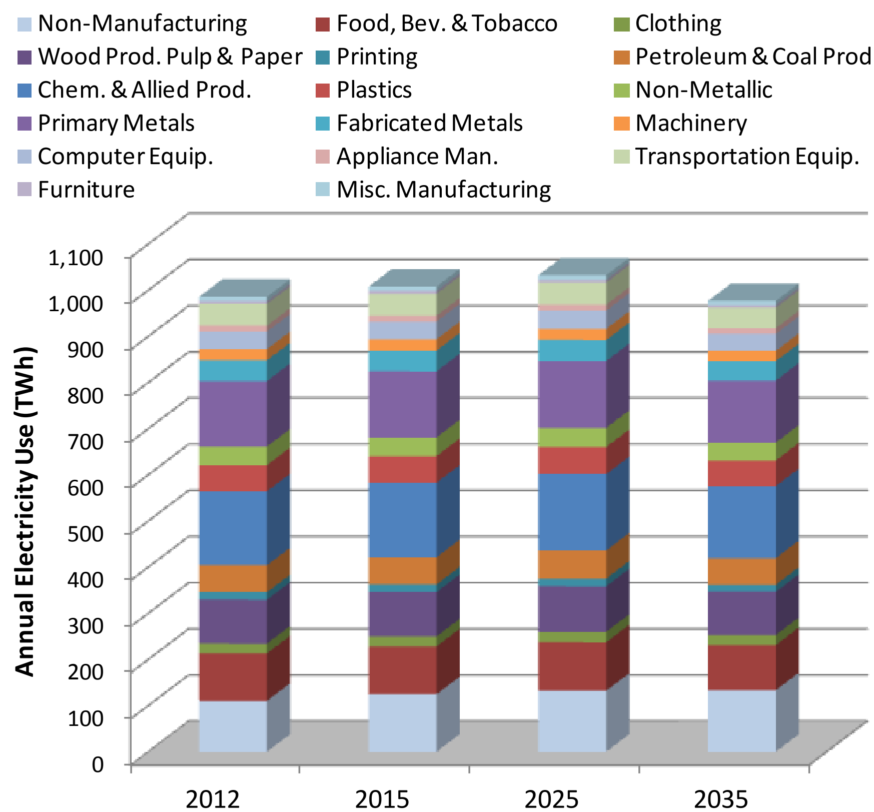

Figure 3-26
U.S. Industrial Electricity Forecast by Manufacturing Segment

Figure 3-27 shows the industrial forecast for electricity consumption by process, summed for the total U.S. across manufacturing segments. Electricity consumed for lighting, HVAC and other general purpose uses is grouped as industrial facilities and comprises the largest share of industrial end-use consumption, about 17% throughout the forecast.

Electrochemical processes are about 12%, and both process cooling and refrigeration, and other uses are about 10%. The remaining processes consume less than 10% of total industrial electricity.

On the low end are the material handling and steam generation equipment categories which both have about 2% of total consumption over the forecast period.

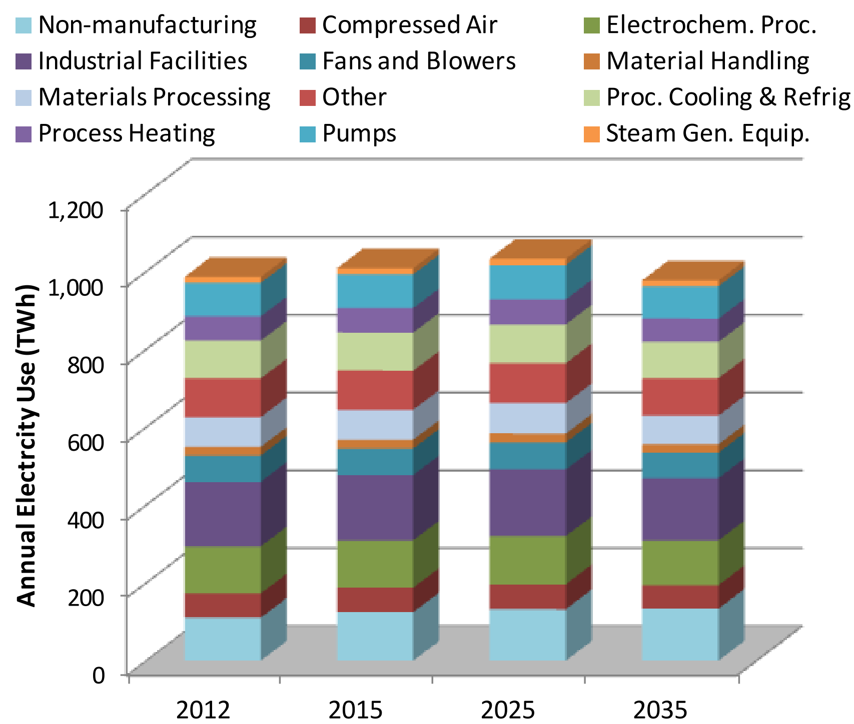

Figure 3-27
U.S. Industrial Electricity Forecast by Process

Industrial Electric Intensity

Overall, industrial electricity user per employee, or intensity, is expected to increase with a CAGR of 0.9%, and total growth of 23% from 2012 to 2035. In 2012 electricity use per employee was 74, 651 kWh per employee, with an increase to 91, 695 kWh per employee forecast in 2035. The increase in intensity is primarily due to a decrease in manufacturing employment. The number of employees is forecast to decrease by 22% according to the AEO. Therefore although industrial consumption remains relatively constant, the consumption per employee increases as the number of employees decreases. The forecast of intensity by process is illustrated in Figure 3-28.

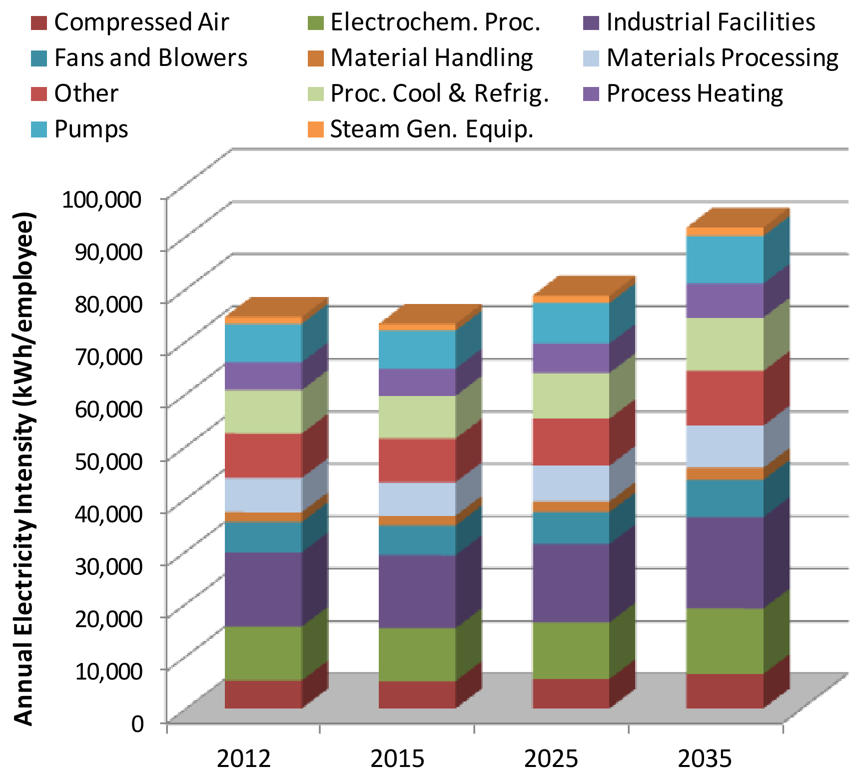

Figure 3-28
Forecast of U.S. Manufacturing Electric Intensity by Process

Coincident Peak Demand Forecast

The summer and winter coincident peak demand forecasts were calculated bottom-up for the residential and commercial sector using saturation forecasts and end-use demand data. For the industrial sector the demand forecast was calculated from the energy forecasts using assumed load and coincidence factors.

Figure 3-29 illustrates the summer coincident demand forecast broken out by Census region. The South Census region accounts for over 47% of total U.S. summer demand over the forecast period. This is expected due to higher electricity consumption for space cooling in the South, which is the main driver for system peak.

Similarly to electricity consumption, both the South and West Census regions are forecast to increase summer demand by about 26% and 33%, respectively, from 2012 to 2035. Forecast growth from 2012 to 2035 for the Northeast and Midwest Census regions is more moderate with 5% and 6% respectively.

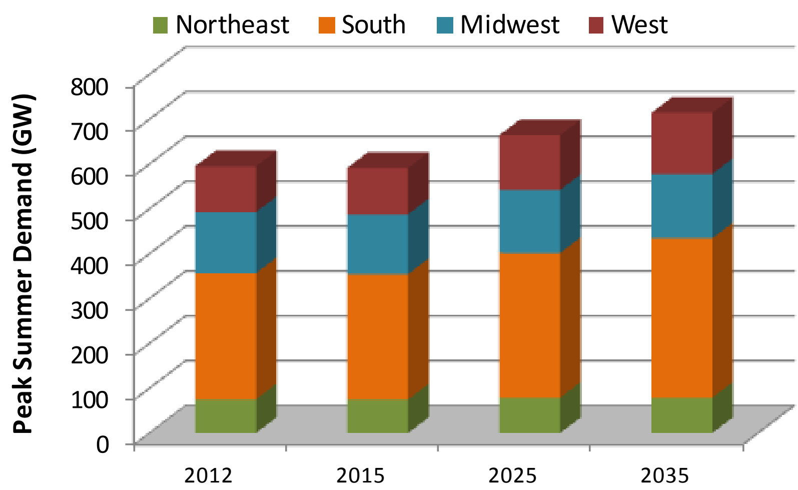

Figure 3-29
U.S. Summer Coincident Peak Demand Forecast by Census Region

Table 3-10 breaks out the summer coincident demand forecast by Census region and division. The residential sector accounts for about 50% of summer demand, again due to cooling load which drives system peak.

Table 3-10
U.S. Summer Coincident Peak Demand Forecast by Census Region and Sector (GW)

	2012	2015	2025	2035	% Change (2012-2035)	CAGR (2012-2035)
By Census Region						
Northeast	75	75	79	79	5%	0.2%
South	281	280	323	356	26%	1.0%
Midwest	136	133	141	143	6%	0.2%
West	102	104	122	137	33%	1.3%
Total	**595**	**591**	**664**	**714**	**20%**	**0.8%**
By Sector						
Residential	289	279	331	373	29%	1.1%
Commercial	165	168	186	202	22%	0.9%
Industrial	141	144	147	139	-1%	0.0%
Total	**595**	**591**	**664**	**714**	**20%**	**0.8%**

Note: Numbers in table may not sum to the total due to rounding.

Figure 3-30 illustrates the winter coincident peak demand forecast broken out by Census region. Again the South has the highest share, over 43%, throughout the forecast period, whereas the Northeast accounts for less than 14%. This points to the increased saturation of electricity for water and space heating in the South, where direct-use of fossil fuels have the majority in other regions.

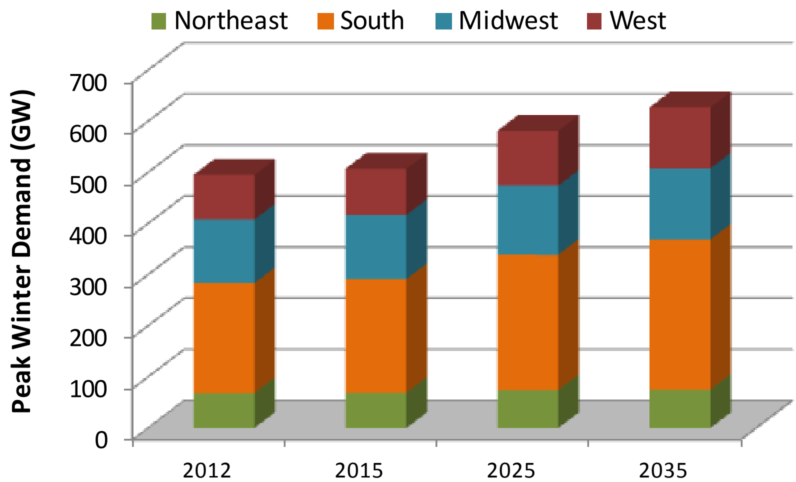

Figure 3-30
U.S. Winter Coincident Peak Demand Forecast by Census Region

Table 3-11 breaks out winter demand by Census region and sector. Again the residential sector has the largest share of winter demand although not quite as high as summer demand.

Following electricity consumption, industrial summer and winter demand are forecast to decrease slightly between 2012 and 2035.

Table 3-11
U.S. Winter Coincident Peak Demand Forecast by Census Region and Sector (GW)

	2012	2015	2025	2035	% Change (2012-2035)	CAGR (2012-2035)
By Census Region						
Northeast	69	69	75	76	10%	0.4%
South	215	222	265	293	36%	1.4%
Midwest	124	125	135	139	12%	0.5%
West	88	91	107	120	37%	1.4%
Total	**496**	**507**	**582**	**628**	**27%**	**1.0%**
By Sector						
Residential	208	214	267	306	47%	1.7%
Commercial	147	149	167	182	24%	1.0%
Industrial	141	144	147	139	-1%	0.0%
Total	**496**	**507**	**582**	**628**	**27%**	**1.0%**

Note: Numbers in table may not sum to the total due to rounding.

Residential Peak Demand Forecast

Figure 3-31 shows the shares of residential summer and winter coincident peak for each housing segment. Because these forecasts are calculated bottom up for each housing segment in the U.S. as a whole, the total demand forecast does not match the U.S. demand forecast summed from the division level. Therefore the shares by building type are shown as a portion of the whole.

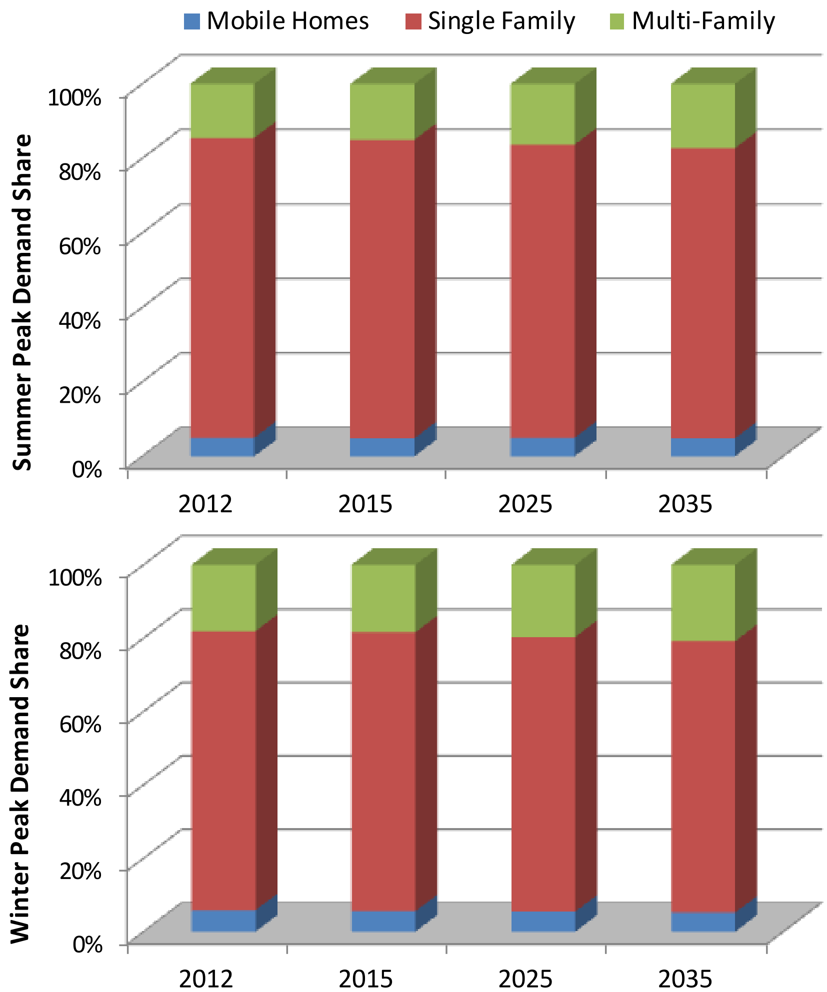

Figure 3-31
U.S. Residential Coincident Peak Demand Forecast by Housing Segment

The shares of residential demand by type of home are very similar for summer and winter peak demand with mobile and multi-family homes having slightly higher shares in winter demand. This is likely due to higher use of electricity for space and water heating compared to single family homes.

1.1% CAGR for summer demand and 1.7% for winter demand. 29% increase and 47% increase. Single family accounts for between 78 and 81% of residential summer and winter demand throughout the forecast. Shares are nearly identical, in both cases there is a few percent decrease in the single family share and a few percent increase in the multi-family share.

Table 3-12 shows the absolute percent change, and the compound annual growth rate (CAGR) for summer and winter demand for each division and at the Census region level. Similarly to the energy forecasts, demand in both the South and West Census regions is forecast to grow at a faster rate the in the Northeast and Midwest.

In general winter demand is expected to have higher growth as a result of increased electricity for space and water heating.

Table 3-12
U.S. Residential Demand Forecast Growth by Division

	Summer		Winter	
	% Change (2012-2035)	**CAGR (2012-2035)**	**% Change (2012-2035)**	**CAGR (2012-2035)**
New England	5%	0.2%	19%	0.7%
Middle Atlantic	16%	0.6%	30%	1.1%
Northeast Total	**13%**	**0.5%**	**26%**	**1.0%**
South Atlantic	50%	1.8%	69%	2.3%
Florida	42%	1.5%	59%	2.0%
East South Central	20%	0.8%	37%	1.4%
West South Central	19%	0.8%	62%	2.1%
Texas	31%	1.2%	68%	2.3%
South Total	**35%**	**1.3%**	**60%**	**2.1%**
West North Central	8%	0.3%	22%	0.9%
East North Central	17%	0.7%	38%	1.4%
Midwest Total	**11%**	**0.5%**	**27%**	**1.0%**
Mountain North	71%	2.4%	68%	2.3%
Mountain South	63%	2.1%	69%	2.3%
Pacific	30%	1.1%	54%	1.9%
California	33%	1.2%	48%	1.7%
West Total	**45%**	**1.7%**	**55%**	**2.0%**
U.S. Total	**29%**	**1.1%**	**47%**	**1.7%**

Figure 3-32 shows summer coincident peak demand broken out by end use. Heat pumps for space cooling and other space cooling (central and room AC) account for over a third of residential summer demand. Other end uses like lighting and water heating whose summer operation is less coincident with system summer peak have a share.

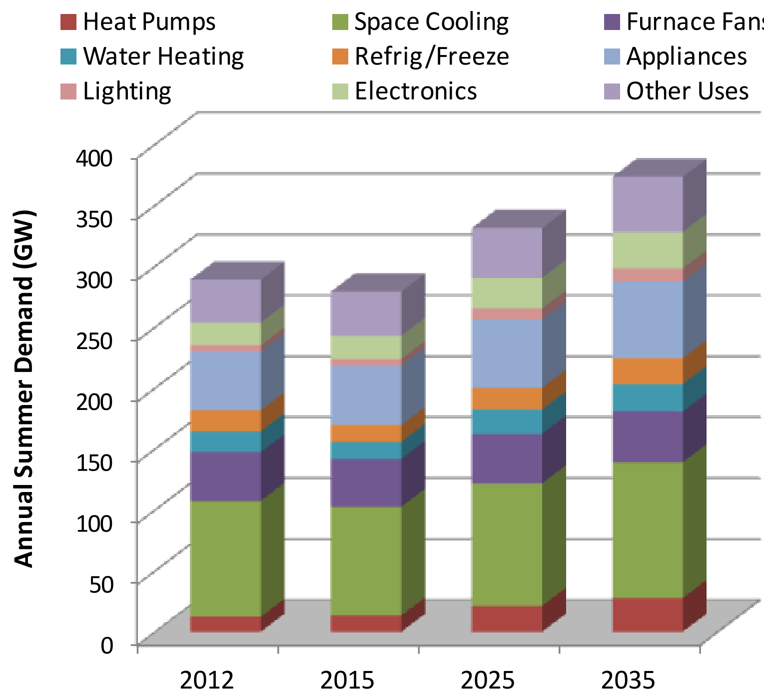

Figure 3-32
U.S. Residential Coincident Summer Peak Demand Forecast by End Use

Figure 3-33 shows winter coincident peak demand broken out by end use. Weather-dependent end uses including all space heating, furnace fans and water heating account for about 40% of winter demand.

There is little difference between summer and winter demand for appliances including refrigerators and freezers, which are around 25% of both summer and winter demand.

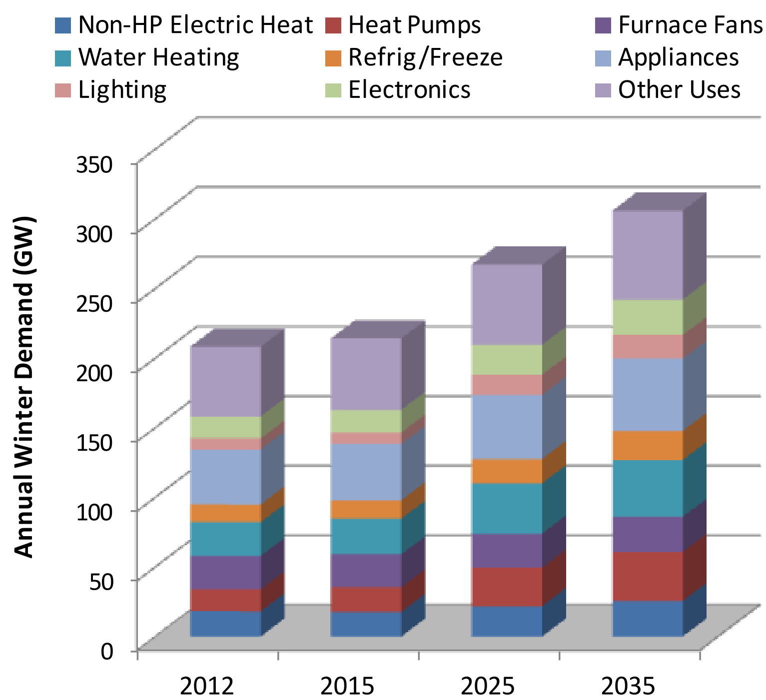

Figure 3-33
U.S. Residential Coincident Winter Peak Demand Forecast by End Use

Commercial Peak Demand Forecast

The shares of summer and winter demand by building type are shown in Figure 3-34. Only summer peak is shown, the shares of total commercial demand are nearly the same for winter peak.

Again because these forecasts are calculated bottom up for each housing segment in the U.S. as a whole, the total demand forecast does not match the U.S. demand forecast summed from the division level. Therefore the shares by building type are shown as a portion of the whole.

Retail buildings account for about 20% of total demand over the forecast period. Health care has the lowest share of building peak demand at about 4%.

In absolute terms the demand forecasts show over one percent annual growth for health care, lodging, large and small offices, and other buildings. In other building types, the demand forecast has less than one percent compound annual growth.

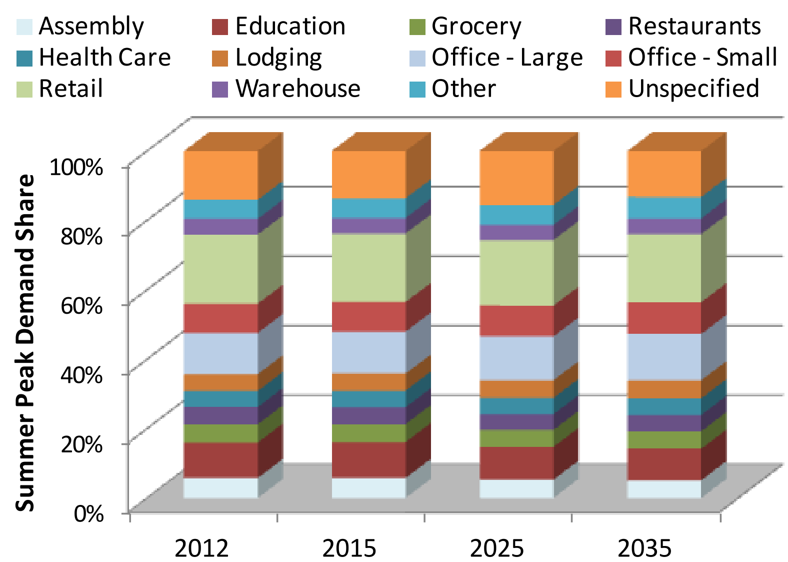

Figure 3-34
U.S. Commercial Coincident Peak Demand Forecast, Shares by Building Type

Table 3-13 shows the absolute percent change, and the compound annual growth rate (CAGR) for summer and winter demand for each division and at the Census region level. Unlike the residential sector summer and winter demand growth are on the same scale in the commercial sector, with only slightly higher growth forecast for winter demand.

Table 3-13
U.S. Commercial Demand Forecast Growth by Division

	Summer		Winter	
	% Change (2012-2035)	CAGR (2012-2035)	% Change (2012-2035)	CAGR (2012-2035)
New England	15%	0.6%	15%	0.6%
Middle Atlantic	9%	0.4%	9%	0.4%
Northeast Total	**10%**	**0.4%**	**11%**	**0.4%**
South Atlantic	29%	1.1%	32%	1.2%
Florida	29%	1.1%	32%	1.2%
East South Central	22%	0.9%	24%	0.9%
West South Central	21%	0.8%	27%	1.0%
Texas	21%	0.8%	27%	1.0%
South Total	**25%**	**1.0%**	**29%**	**1.1%**
West North Central	15%	0.6%	17%	0.7%
East North Central	14%	0.6%	17%	0.7%
Midwest Total	**14%**	**0.6%**	**17%**	**0.7%**
Mountain North	34%	1.3%	35%	1.3%
Mountain South	34%	1.3%	35%	1.3%
Pacific	30%	1.2%	34%	1.3%
California	30%	1.2%	34%	1.3%
West Total	**30%**	**1.2%**	**33%**	**1.3%**
U.S. Total	**22%**	**0.9%**	**24%**	**1.0%**

Figure 3-35 shows commercial summer coincident peak demand broken out by end use. Other uses has a sizeable share of the total which is in line with the commercial energy forecast.

Space cooling from heat pumps, central AC and chillers accounts for almost 20% of total summer demand. Lighting has a larger share of commercial summer demand as its use is more coincident with system peak than in the residential sector. Like the residential sector water heating has a small share of commercial summer demand.

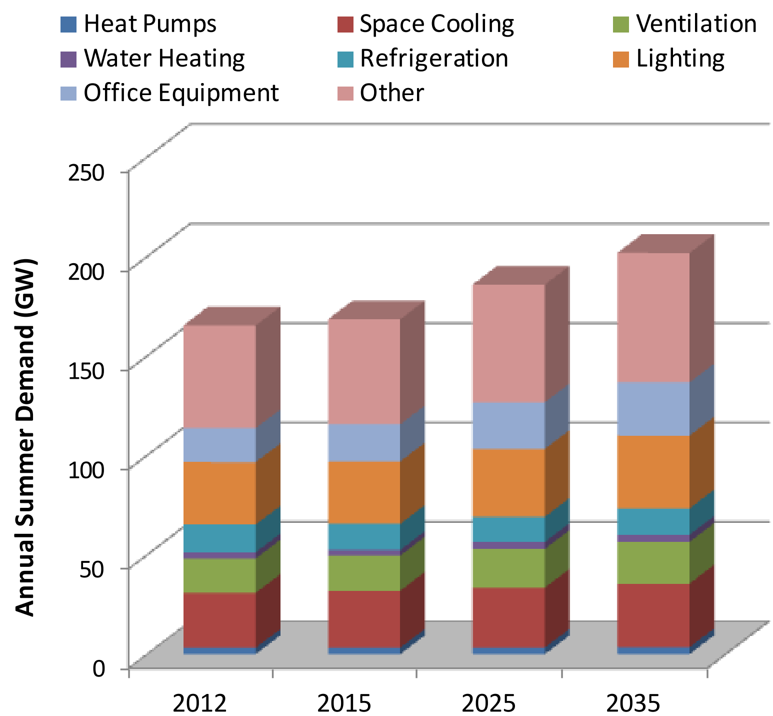

Figure 3-35
U.S. Commercial Coincident Summer Peak Demand Forecast by End Use

Figure 3-36 shows winter coincident peak demand broken out by end use. Weather-dependent end uses including all space heating, ventilation and water heating account for about 30% of commercial winter demand. This includes non-heat pump space heating which is included with other uses in Figure 3-36.

There is little difference between summer and winter demand for other end use categories, in all most commercial end uses have slightly lower winter demand due to timing of system peak compared to typical commercial hours of operation.

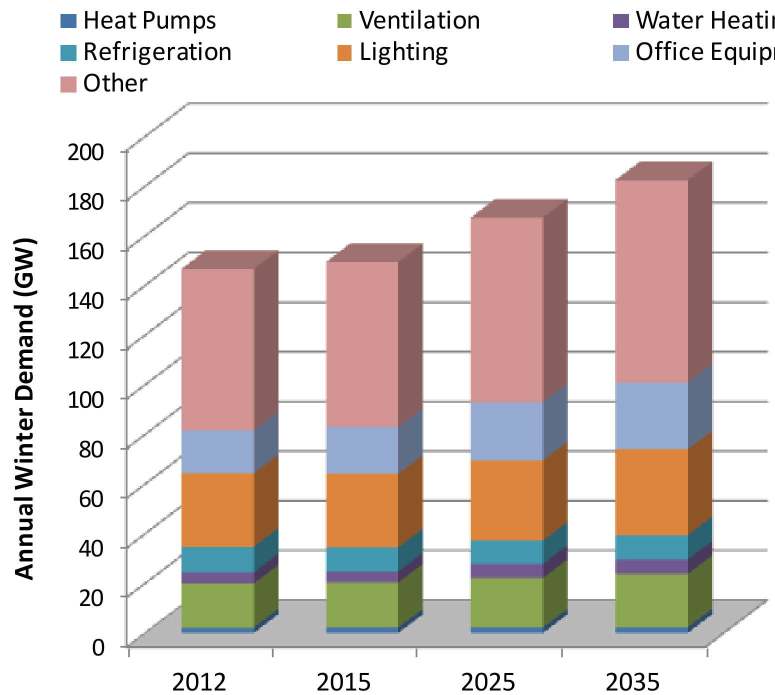

Figure 3-36
U.S. Commercial Coincident Winter Peak Demand Forecast by End Use

Industrial Peak Demand Forecast

Figure 3-37 shows the industrial coincident peak demand broken out by manufacturing segment. Summer and winter demand are the same in the industrial sector.

The trends found in the industrial energy forecast apply to the demand forecast as well. Non-manufacturing accounts for 11% of industrial demand in 2012, growing to 14% in 2035. Of the manufacturing segments, chemicals and allied products has the highest share (16%), followed by primary metals (14%), and food, beverage and tobacco, and wood products, paper and pulp both at 10% of industrial. The other manufacturing segments each represent less than 10% of industrial demand in the U.S. as a whole.

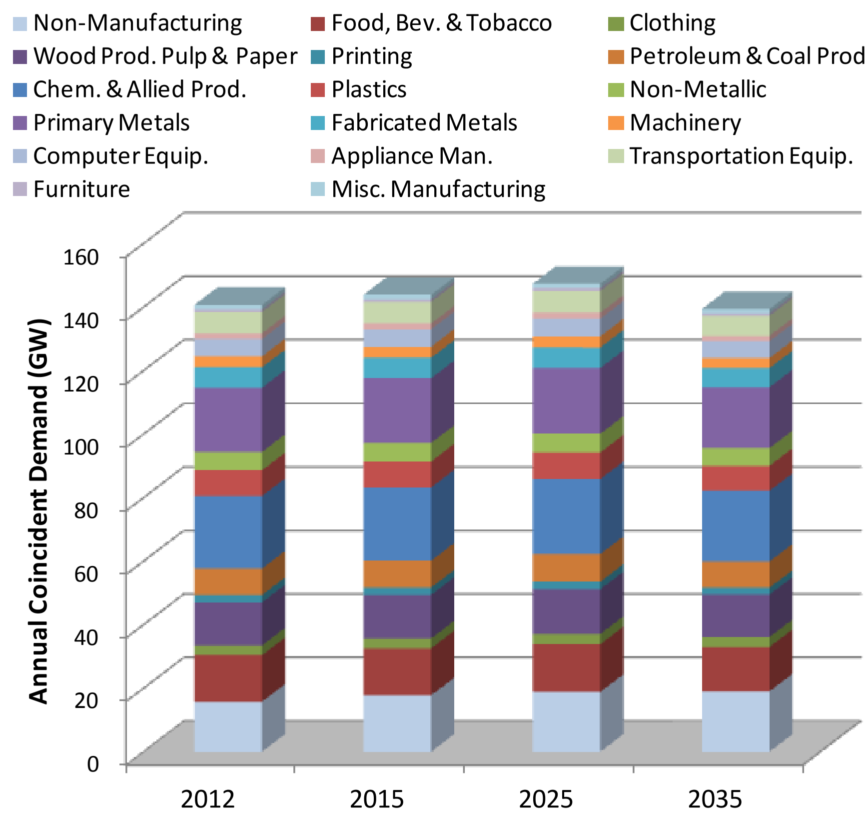

Figure 3-37
U.S. Industrial Coincident Peak Demand Forecast by Manufacturing Segment

Table 3-14 shows the absolute percent change, and the compound annual growth rate (CAGR) for coincident demand for each division and at the Census region level. Growth is expected in the South and West Census regions, while demand is expected to decline in the Northeast and Midwest.

Table 3-14
U.S. Industrial Demand Forecast Growth by Division

	% Change (2012-2035)	CAGR (2012-2035)
New England	-24%	-1.2%
Middle Atlantic	-25%	-1.2%
Northeast Total	**-25%**	**-1.2%**
South Atlantic	7%	0.3%
Florida	7%	0.3%
East South Central	7%	0.3%
West South Central	8%	0.3%
Texas	8%	0.3%
South Total	**7%**	**0.3%**
West North Central	-11%	-0.5%
East North Central	-8%	-0.4%
Midwest Total	**-10%**	**-0.5%**
Mountain North	7%	0.3%
Mountain South	7%	0.3%
Pacific	10%	0.4%
California	10%	0.4%
West Total	**9%**	**0.4%**
U.S. Total		

Figure 3-38 illustrates industrial demand broken out by process. Similarly to the consumption forecast, the industrial facilities end-use category has the highest share of industrial coincident demand.

Electrochemical processes are about 12%, and both process cooling and refrigeration, and other uses are about 10%. The remaining processes account for less than 10% of total industrial demand each.

On the low end are the material handling and steam generation equipment categories which both have about 2% of total demand over the forecast period.

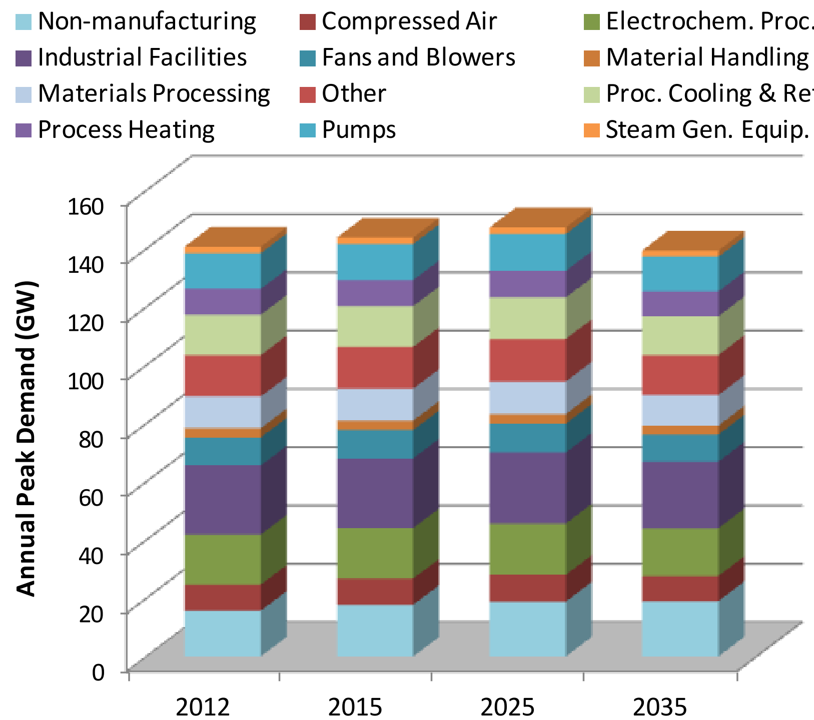

Figure 3-38
U.S. Industrial Coincident Peak Demand Forecast by Process

Price Forecasts

For the residential and commercial sectors where efficiency is assessed from the bottom up, retail rates and avoided cost forecasts are used in calculating benefits and costs associated with efficiency measures.

All costs and rates are in real dollars and avoided costs inputs are assumed to be at the source. Additional factors are used to take the cost data from the source and calculate costs at the customer meter.

Costs and rates are provided as forecasts from 2010 to 2055. Although the period of study only runs to 2035, the extra years allow the lifetime benefits and costs to be calculated for all measures. Most measures have a life of less than 20 years and therefore 2055 is sufficient.

Avoided Costs

Avoided capacity and energy costs are used to calculate utility benefits from efficiency measures. These are applied seasonally, and avoided energy costs are also applied for on- and off-peak periods in each season. The avoided capacity costs are applied to coincident demand savings and avoided energy costs are applied to annual energy savings, both are applied on an annual basis over the life of the measure.

The avoided transmission costs used in this study are 15 $/kW at the source, for both summer and winter and these remain constant over the forecast period. Avoided generation costs for the winter are assumed to be zero.

The summer avoided generation capacity costs and average avoided energy costs for 2012 and 2035 for each division are shown in Table 3-15.

Over the forecast period the avoided generation costs have about a 1% CAGR, with 1.3% CAGR for avoided energy costs. These are real costs and therefore do not escalate much over the forecast period. All costs are held constant after 2035.

Table 3-15
Avoided Generation and Energy Costs by Division

	Summer Avoided Generation Costs (per kW at Source)		Avoided Energy Costs (per kWh at Source)	
	2012	**2035**	**2012**	**2035**
New England	$54	$68	$0.058	$0.079
Middle Atlantic	$48	$60	$0.058	$0.079
South Atlantic	$61	$76	$0.065	$0.089
East North Central	$37	$46	$0.040	$0.054
East South Central	$49	$62	$0.053	$0.072
West North Central	$50	$62	$0.053	$0.070
West South Central	$48	$60	$0.052	$0.070
Mountain North	$49	$61	$0.052	$0.071
Mountain South	$49	$61	$0.052	$0.071
Pacific	$50	$63	$0.054	$0.074
Florida	$61	$76	$0.065	$0.089
Texas	$48	$60	$0.052	$0.070
California	$50	$63	$0.054	$0.074
United States	$51	$64	$0.055	$0.075

To calculate the avoided costs at the meter from the values for the source generation capacity reserve margin, demand line loss factors and energy line loss factors are used. The generation capacity reserve margin[26] represents the typical amount of generating capacity a utility must have above and beyond peak system demand. This margin is defined for system reliability purposes, where this excess capacity is available in case there are major failures in a system. In the U.S. reserve capacity margins are around 15%, defined regionally where some are slightly higher or lower.

[26] Today in Energy, "Reserve electric generating capacity helps keep the lights on," U.S. DOE EIA, Washington DC, June 2012. http://www.eia.gov/todayinenergy/detail.cfm?id=6510

The loss factors take into account system losses to move the cost data from the point of generation (source) to the point of delivery (customer meter). Typical values for the reserve margin and loss factors for the residential and commercial sectors are shown in Table 3-16. The energy line loss factor has no seasonality.

Table 3-16
Generation Reserve Margin and Loss Factors

	Summer	Winter
Residential		
Generation Capacity Reserve Margin	15.0%	15.0%
Demand Line Loss Factors	15.0%	12.0%
Energy Line Loss Factors	12.0%	
Commercial		
Generation Capacity Reserve Margin	15.0%	15.0%
Demand Line Loss Factors	12.0%	7.5%
Energy Line Loss Factors	7.5%	

The capacity reserve margins and loss factors are used as follows to calculate the avoided costs at the meter. A single value for the avoided capacity costs (*G&TCapCosts*) is calculated from the avoided generation capacity and avoided transmission capacity costs, using the following formula. The same formula is used for summer and winter substituting the appropriate seasonal values.

$$G\&TCapCosts_{meter} = \frac{GenCapCosts_{source} * (1 + Gen\_Margin)}{(1 - Demand\_Loss\_Factor)} + \frac{TransCapCosts_{source}}{(1 - Demand\_Loss\_Factor)}$$

The avoided energy costs at the meter are calculated using the following equation.

$$EnergyCosts_{meter} = \frac{EnergyCosts_{source}}{(1 - Energy\_Loss\_Factor)}$$

Retail Rates

Retail rates are used to calculate customer benefits from bill savings over the life of efficiency measures. Although these are not used in calculating the Total Resource Cost test, the primary test of cost-effectiveness used in this study, the assumptions for residential and commercial rates by division are shown in Table 3-17. The U.S.

values are a load-weighted average of the divisional values. The EPRI rates are in line with those presented in the *AEO2012* Reference case.

Table 3-17
Residential and Commercial Retail Electricity Rates by Division

	Residential ($/kWh)	Commercial ($/kWh)
New England	$0.16	$0.14
Middle Atlantic	$0.16	$0.14
South Atlantic	$0.11	$0.10
East North Central	$0.12	$0.09
East South Central	$0.10	$0.10
West North Central	$0.10	$0.08
West South Central	$0.11	$0.09
Mountain North	$0.11	$0.09
Mountain South	$0.11	$0.09
Pacific	$0.13	$0.12
Florida	$0.11	$0.10
Texas	$0.11	$0.09
California	$0.13	$0.12
United States	$0.12	$0.10

Section 4: Energy Efficiency Potential

The baseline development process and energy use modeling described in the previous sections results in a set of energy efficiency potential estimates. These impacts are presented in the form of technical, economic, high achievable, and achievable potentials, each embodying a set of assumptions about the implementation and acceptance of energy efficiency activities. This section first presents the potential savings for energy efficiency at the national level, followed by a discussion of each of the primary customer sectors. This section also presents estimates of potential savings from efficiency programs at the U.S. Census division level.

Summary of National Results

The energy savings potentials associated with energy efficiency are displayed in Figure 4-1, each expressed as a percentage of the baseline U.S. electricity consumption for that year. As expected, the savings increase over time as efficient technologies are phased in through equipment turnover. In addition, the savings are largest for technical potential and progressively reduced through the refinements applied to estimate the other potentials. The achievable potential reaches 10.8% of the baseline by 2035.

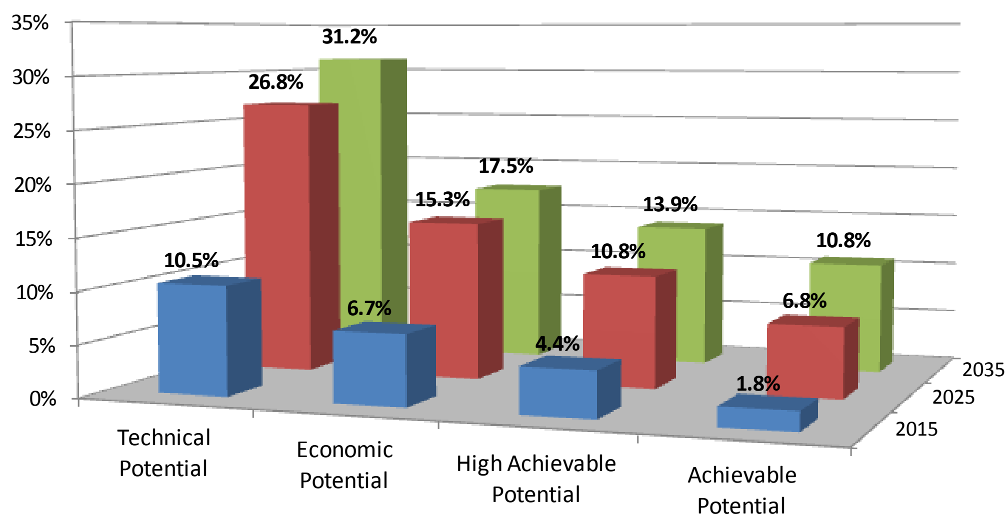

Figure 4-1
Energy Efficiency Potential Estimates as Percentages of Energy Baseline

These savings potentials represent the combined effects of energy efficiency efforts in the three primary market segments – residential, commercial, and industrial. While the specific measures vary between sectors, the overall impacts are comparable. The achievable potential for each sector is displayed in absolute terms in Table 4-1, and as a percentage of each sector's baseline in Figure 4-2.

Interestingly, although the baselines for energy use in the residential and commercial sectors are within 10% of each other, the achievable potential in the commercial sector is over twice the achievable potential in the residential sector, both in absolute terms and as a percent of their respective baselines. In absolute energy savings, the industrial estimate is less than half that of the residential sector, and is less than 20% of the commercial savings.

Table 4-1
Achievable Potential by Sector (GWh)

Sector	2015	2025	2035
Residential	10,971	58,093	138,505
Commercial	46,115	174,719	293,822
Industrial	11,631	51,395	55,610
Total	**68,718**	**284,208**	**487,937**

Note: Numbers in table may not sum to the total due to rounding.

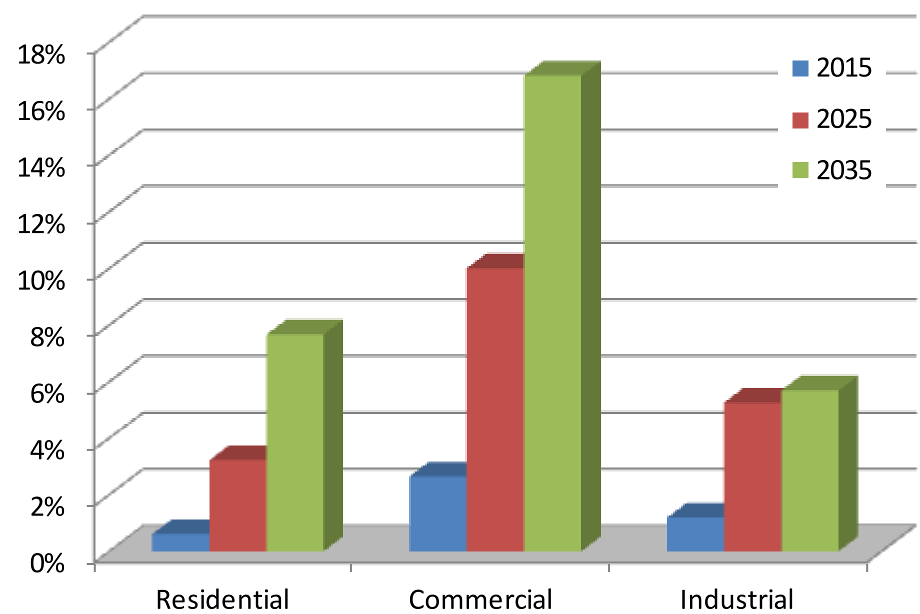

Figure 4-2
Achievable Potential by Sector, as Percentage of Sector Energy Baseline

It is useful to view these potential estimates in the context of historical electricity consumption and the baseline forecast. Figure 4-3 displays the energy use associated with each of the four potential estimates over time.

The baseline compound annual growth rate (CAGR) between 2012 and 2035 is 0.85% for residential, commercial and industrial sectors in total, the achievable potential reduces this CAGR to 0.36%. Under an ideal set of conditions conducive to energy efficiency programs, this growth rate can be reduced to as low as 0.20% per year considering the high achievable potential.

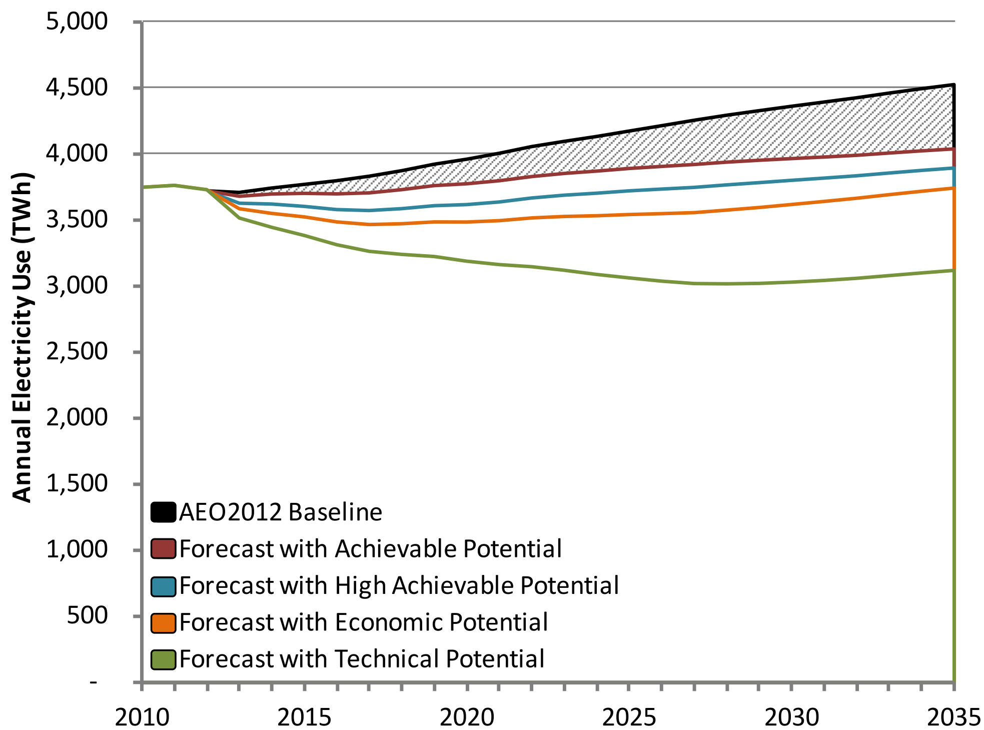

Figure 4-3
U.S. Energy Efficiency Potentials in Context of the Baseline Forecast

The technical potential represents the adoption of the most efficient available technologies and as these technologies are rolled into the baseline and approach market saturation, beginning around 2025, a change of slope occurs. This can also be seen in Figure 4-3 to a lesser extent in the economic potential. However because of the dynamics of passing measures changing over time and changes to market and program barriers, the economic potential and achievable potentials tend to show a more steady increase over time.

In the 2009 National Study technologies were screened for cost effectiveness only once at the beginning of the study period, and where technology options and costs were kept static throughout the time period, this effect was more pronounced. To capture savings from technologies that may not be available today, this update includes future technologies and equipment cost reductions after 2020 allowing the economic and achievable potentials to continue to increase later in the forecast.

By comparing the baseline forecast in Figure 4-3 with the achievable potential, it can be seen that energy efficiency efforts can realistically expect to offset 61% of load growth between 2012 and 2035.

Residential Sector

Figure 4-4 illustrates the *AEO2012* residential baseline electricity forecast and the forecast with the impacts of the efficiency potential estimates included. The baseline CAGR between 2012 and 2035 for the residential sector is 1.06%, and the achievable potential reduces this growth to 0.71%.

The wide margin between the technical and economic potential suggests that although technology options are available that provide energy savings, only a portion of that energy savings is cost effective. It may be that in some end-use categories no measures pass the benefit-cost evaluation, or more likely the cost-effective technologies simply do not provide as much energy savings.

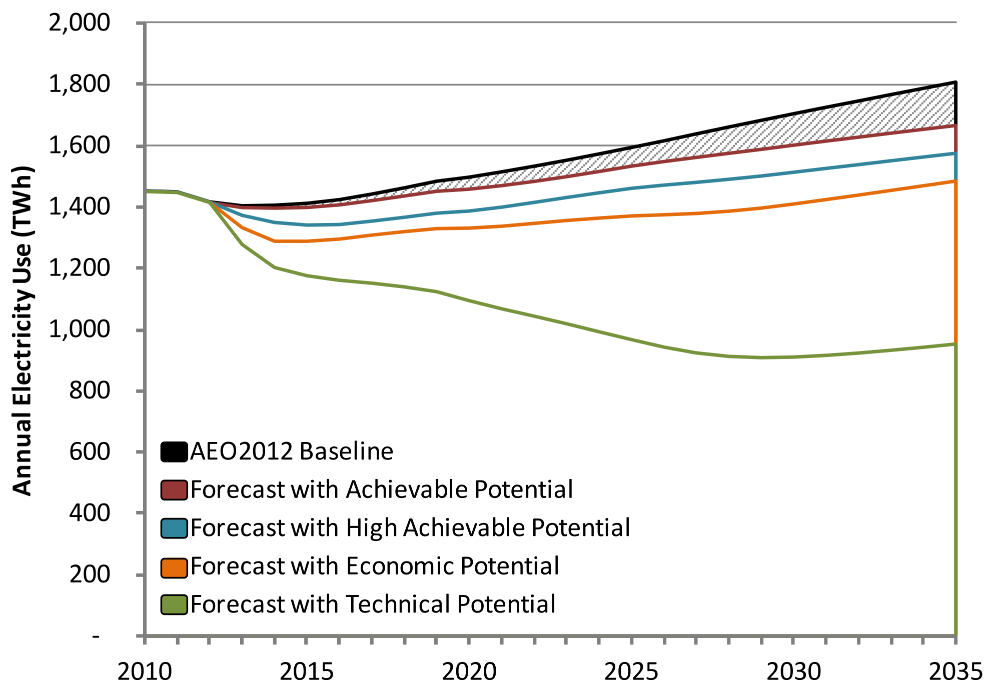

Figure 4-4
Residential Energy Efficiency Potentials in Context of the Baseline Forecast

Figure 4-5 illustrates residential electricity use in the bookend years of this study and shows the 2035 impacts of achievable potential (AP) and high achievable potential (HAP) energy reductions at the end-use level.

The residential sector has been a primary focus for energy efficiency both through energy efficiency programs and implementation of codes and standards. These programs have historically focused on areas with high electricity usage to produce targeted reductions in energy consumption. As such, end uses such as lighting are expected to see a decline in consumption over the forecast period. This can also mean that there are less opportunities for additional program-driven efficiency if the baseline technologies are highly efficient and it is difficult to find cost-effective options that save more energy.

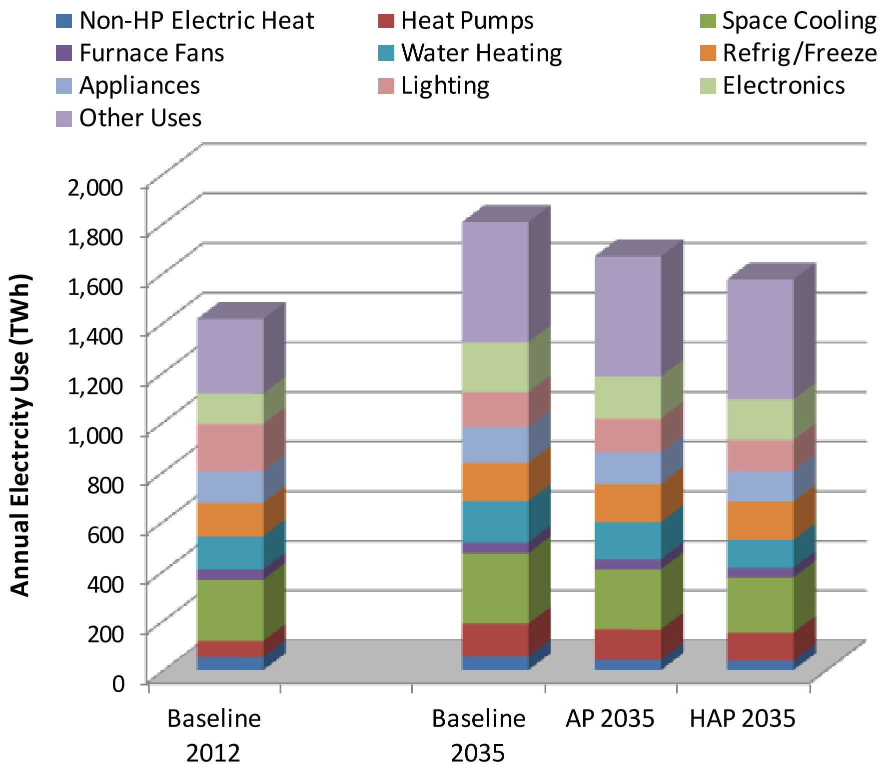

Figure 4-5
Residential Sector Energy Baseline and Achievable Potentials by End Use

Residential Savings in Terms of Use per Household

Because the forecast horizon contains implicit growth driven by both social and macroeconomic factors, it is useful to examine the energy intensity associated with the baseline and potential cases. These values normalize electricity consumption by removing the effects of population, economic development, and other drivers, allowing an analysis of efficiency on a per-unit basis. In the residential sector, the normalizing variable is number of households, as forecasted in *AEO2012*. The baseline for 2012 and 2035, along with the intensity including the impacts of the high and achievable potential for 2035, are presented in Figure 4-6.

There is a clear increase in energy intensity for heat pumps and other uses, while lighting and space cooling decrease in intensity. The lighting reduction reflects the impacts of EISA 2007 where the amount of watts needed to produce the equivalent output will be reduced. Some of the change in space conditioning may be a shift from central AC for space cooling to heat pumps used for both space heating and cooling.

The other uses category is likely to contain energy savings potential beyond what is captured in this study. A better understanding of the technologies included in this category is necessary, particularly consumer electronics. As this category is better understood it is also likely that additional codes and standards will come into play to increase efficiency in energy conversion.

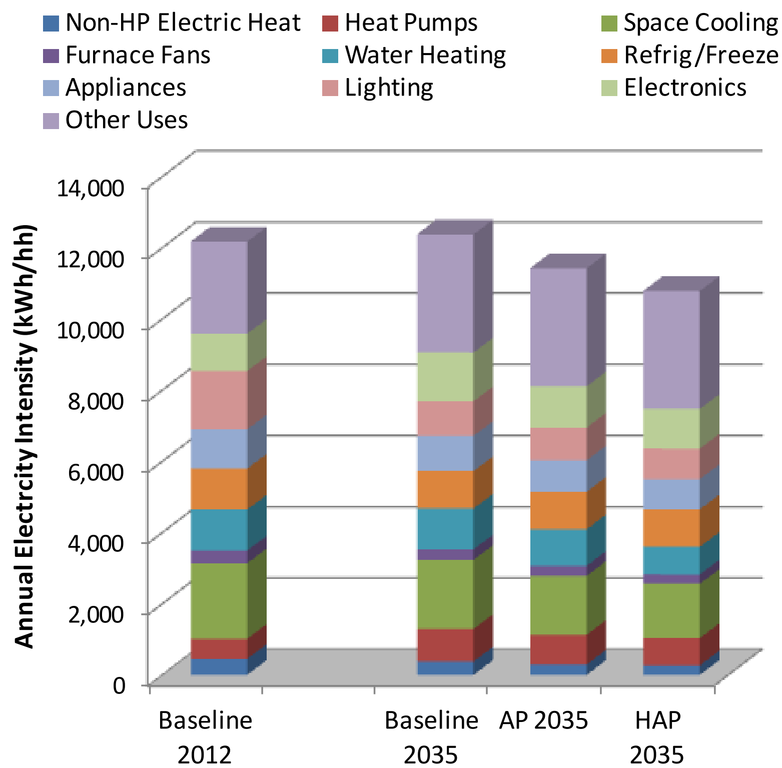

Figure 4-6
Residential Sector Energy Intensity Baseline and Achievable Potentials by End Use

Residential Savings Potential by End Use

Before breaking the residential savings potential into end uses it is important to understand the treatment of space heating and space cooling. The AEO baselines used as a reference for savings in this study are developed from *AEO2012* micro datasets which break the forecast down by end use and technology. It is possible to look at electric heating and cooling in terms of heat pumps which provide some heating and cooling, or heating and cooling provided by separate pieces of equipment.

In EPRI's 2009 National Study heating and cooling were treated separately, with heat pumps available as an efficient measure for efficiency replacing the primary electric heating equipment. Heat pumps were not applied for space cooling savings. As such the full cost of the heat pump was applied while only the space heating savings were realized. To provide a more complete treatment of space heating and cooling, the EPRI residential model was updated to apply heat pumps to two heating and cooling categories:

1. Replacing existing air-source heat pumps providing both heating and cooling, and

2. Replacing both a non-heat pump electric heating unit (primary means of space heat) and a central AC.

From 2009 RECS data the share of homes with each combination of space heating and or cooling equipment was determined at the division level, segmented as shown in Figure 4-7 for the total U.S. The three categories treated by EPRI are homes with heat pumps (air-source or ground-source), homes with non-heat pump heating and a central AC, and homes with non-electric heating and central AC.

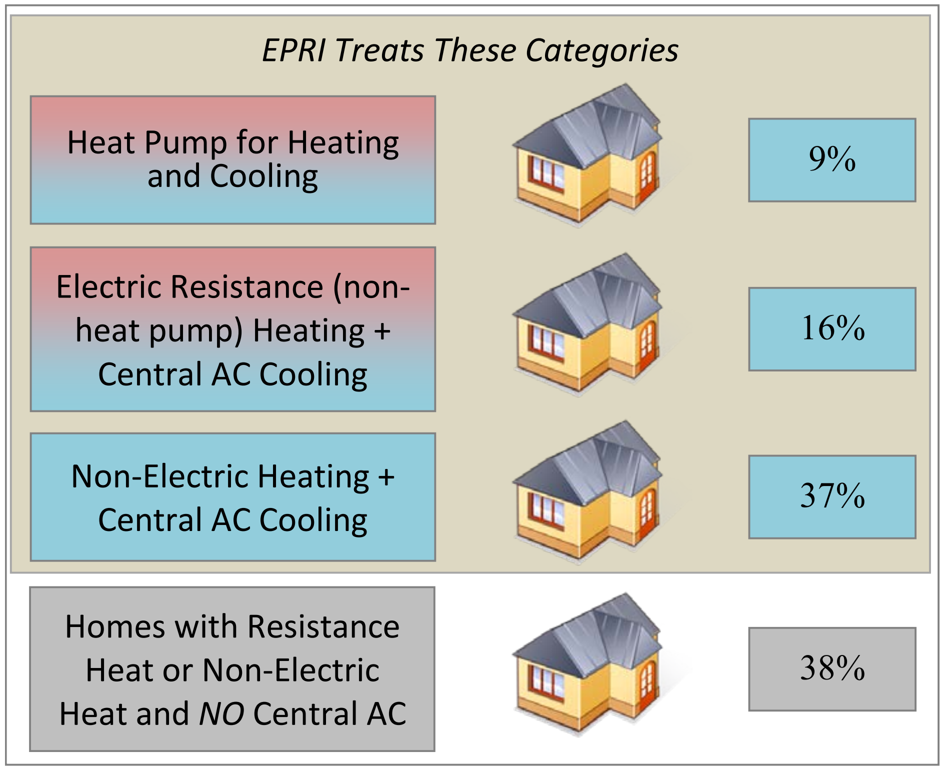

Figure 4-7
Residential Segmentation of Space Heating and Cooling

About 9% of the U.S. has non-heat pump electric heat without central AC cooling, and slightly less than 30% has non-electric heat and no central AC cooling, this study does not treat either of these categories (about 38% of total homes).

Figure 4-8 illustrates how the general *AEO2012* space heating and cooling baselines relate to the categories that EPRI treats for efficiency and finally the savings categories presented in this report. The disconnect between the AEO data and EPRI's treatment comes in the overlap of homes that have central AC and electric or non-electric heating. There is no way to tell how the central AC consumption in the AEO splits between homes that have non-electric versus electric heating. Because EPRI builds its baselines from the bottom up, the first two categories of EPRI's efficiency treatments mix electric heating and cooling, and when the savings are equi-proportionally adjusted to the AEO baselines we present the results as shown on the right-hand side.

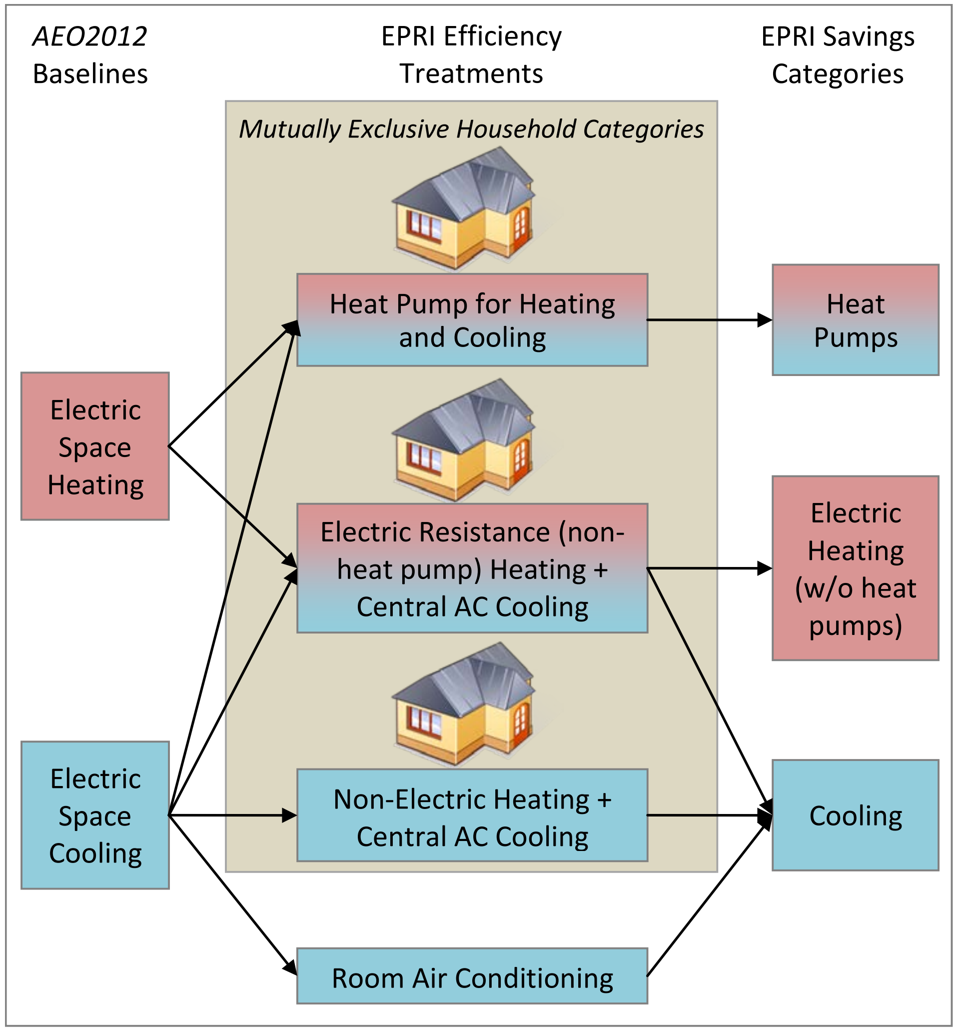

Figure 4-8
Treatment of Space Heating and Cooling Categories

Figure 4-9 presents the achievable potential savings by end use for key forecast years, ordered by the savings in 2035. Cooling presents the biggest opportunities for energy savings over the forecast period, followed by electronics (TVs and PCs). The savings in cooling includes central air conditioning and room air conditioning, and cooling provided by heat pumps replacing non-heat pump heating and a central AC unit (see Figure 4-8).

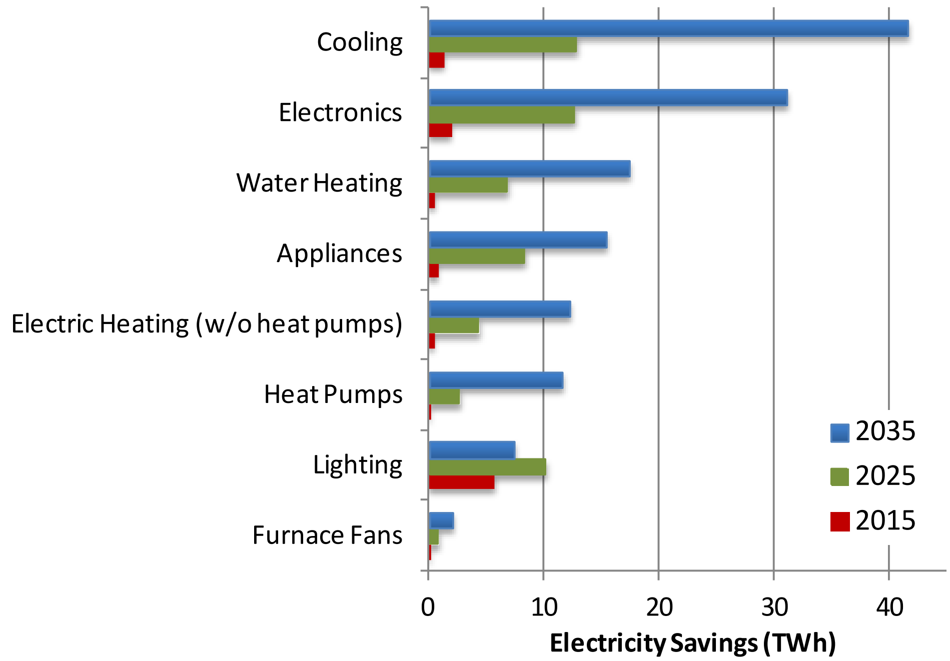

Figure 4-9
Residential Achievable Potential Energy Savings by End Use

Residential Heating and Cooling

Space heating and cooling present significant potential for energy and coincident demand savings in the residential sector. The baseline for heating and cooling is illustrated in Figure 4-10, along with the economic and achievable potential for key forecast years. Significant growth is forecast between 2015 and 2035, about 26%, the majority of the growth coming from heat pumps. Although some growth is expected in most heating and cooling categories, (except room air conditioning, expected to decrease by about 10%), consumption by air-source heat pumps is forecast to increase by 96% over this same period.

The majority of the space heating and cooling savings assessed in this study are realized through heat pumps adopted in homes with non-heat pump electric heating and air conditioning as a baseline. In this case the heat pump is replacing both pieces of equipment. More efficient air-source heat pumps and central AC units affords little opportunity, partly because of codes and standards. Starting in 2015 heat pumps and central AC units must be at least SEER 14, although there are many more efficient units available, they are largely not cost effective. Looking at the passing measures across divisions, only Florida and Texas have units that pass nearly all years in the forecast period due to the high unit energy consumption (UEC) for space cooling. The high UEC results in higher benefits when evaluating the benefit-cost test. Otherwise there is little passing technology for central AC units. This is also true of heat pumps replacing existing heat pumps.

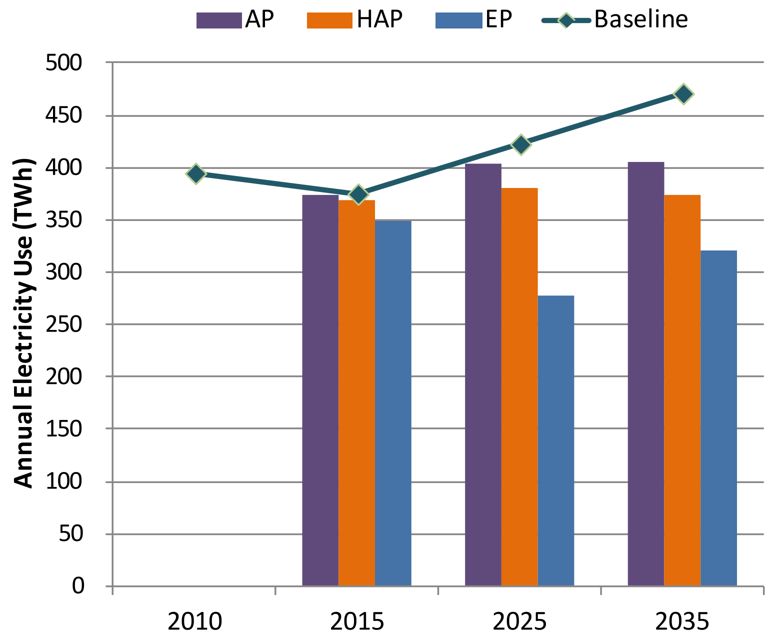

Figure 4-10
Residential Space Heating and Cooling Potential Estimates

On the other hand, a heat pump replacing both a non-heat pump electric heating unit and central AC is much more favorable not only from an energy savings standpoint, but from an economic standpoint. Because a single piece of equipment is being compared to replacing two units, it has a negative incremental cost for low-level measures and increases the potential for high-efficiency heat pumps to pass with the relatively low incremental cost. To account for the fact that both units will likely not fail at the same time, prompting the purchase of a heat pump, the higher of the lifetimes for electric heaters and central AC is used to "slow" the phase in of heat pumps.

The following sections break the 2035 high achievable potential (HAP) and achievable potential (AP) savings into specific efficiency measures. Like most end uses space heating and cooling includes a measure for the primary equipment (the end-use technology) along with secondary measures that have an impact on end-use energy consumption. These can be broken out further for space heating and cooling as follows:

1. Efficient Equipment – These measures correspond directly to electricity consumption, obtaining savings by more efficiently converting electric energy to the delivered energy form (e.g. Btu of cooling).
2. Controls and Shell – These measures do not correlate directly with baseline usage, but rather influence the system in which the electricity-consuming equipment is operating. These measures do not require a unit to burn out before replacement installation, but can instead be modeled as increasingly penetrating the applicable market segment.
3. Shell Measures – Like controls, these measures do not correlate to energy usage and are modeled in the same manner. Most shell improvements are confined to

renovations and new construction, and therefore follow a slower diffusion path than controls.

Residential Space Cooling

Within this section, residential space cooling considers homes with some form of electric space cooling and non-electric space heating. The primary cooling equipment is considered and may be a central AC unit, or one or more room AC units. Measure-level information for homes with central AC and some form of non-heat pump electric heating are treated under the heading of heat pumps.

Figure 4-11 shows the 2035 HAP and AP end-use savings broken out by measure, as a share of the total end-use savings. Note that because it is shown as a percent of the total a measure can have a higher share in the AP than the HAP, even though in absolute terms the HAP is necessarily always higher than the AP.

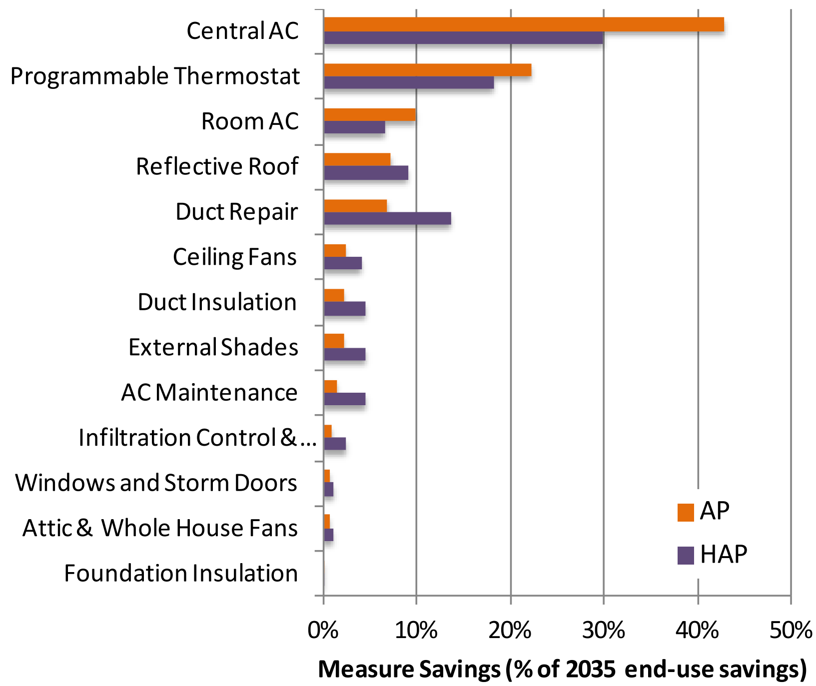

Figure 4-11
Residential Cooling Energy Savings by Measure, as a Percentage of 2035 End-Use Savings

Room AC units pass in five of the thirteen divisions across the entire forecast period (East North Central, East South Central, West South Central, Florida, and Texas). In these divisions the UECs of newly installed base efficiency room air ACs is relatively high (typically above 750 kWh/year) and therefore the benefits are such that an efficient unit passes across the board. They have a lower share of space cooling savings in 2035 due to their lower impacts compared to central ACs.

Central AC units and programmable thermostats have the largest share of space cooling savings in 2035. Note that in many cases secondary measures have a higher shave of 2035 savings in the HAP case than in the AP case. This reflects the impacts of the program implementation factors, or PIFs used to scale the HAP to get the AP. This illustrated the impact that program barriers such as delivery mechanisms have on the achievable potential of individual measures.

Programmable thermostats pass nearly across the board, in all divisions and all years (except in the South Atlantic 2010-2025) and therefore although they have lower energy savings per unit compared to upgrading a central AC, they pass more broadly and therefore have a large overall contribution.

Room AC units pass in five of the thirteen divisions across the entire forecast period (East North Central, East South Central, West South Central, Florida, and Texas). In these divisions the UECs of newly installed base efficiency room air ACs is relatively high (typically above 750 kWh/year) and therefore the benefits are such that an efficient unit passes across the board. They have a lower share of space cooling savings in 2035 due to their lower impacts compared to central ACs.

Residential Heat Pumps

Figure 4-12 shows the heat pump 2035 HAP and AP end-use savings broken out by measure, as a share of the total end-use savings. Heat pumps provide both space heating and cooling using electricity. There are several replacement scenarios covered by heat pumps. They may replace an existing heat pump where a more efficient air- or ground-source heat pump is purchased to replace an existing heat pump at the end of its life.

In addition, for homes with non-heat pump electric heating (i.e., resistance heating) and central air conditioning, a heat pump may replace both of these units to provide heating and cooling for the home. As discussed earlier this is a favorable scenario and with that contributing, heat pump replacement provides the highest share of end-use savings.

Again programmable thermostats always pass the benefit-cost test. Duct repair and infiltration control also both have high rates of passing and duct repair has reasonable savings potential and therefore these two had the second highest share of HAP savings for heat pumps.

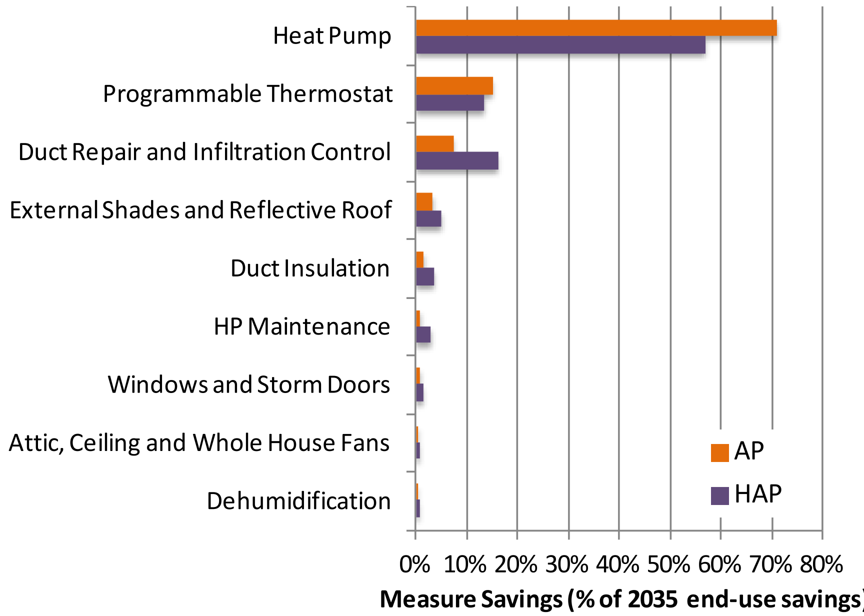

Figure 4-12
Residential Space Heating Energy Savings by Measure, as a Percentage of 2035 End-Use Savings

Residential Electronics

Figure 4-13 shows the electronics (TVs and PCs) baseline along with the impacts of the economic and achievable potential in key forecast years. Together consumption by TVs and PCs is forecast to grow 64%, with over 100% growth in PC consumption between 2012 and 2035. This is expected as part of the proliferation of consumer electronics.

What remains to be seen is how the shift towards smart phones and tablets will impact TV and PC usage. It is likely that some portion of the PC market will shift to tablet devices. However, laptop technology is also rapidly evolving with reduced battery size, solid state hard drives and touch screens to embody several of the benefits associated with tablets.

As such it will behoove us to better understand consumer electronics not currently broken out of the AEO other uses category so that we can better estimate savings potential across the board in consumer electronics.

By 2035, TVs and PCs together represent the second highest category for achievable potential savings. As in the 2009 National Study, a number of factors contribute to these estimates:

- Low marginal cost of efficiency – design choices by manufacturers such as standby power requirements can be incorporated into mainstream products at minimal cost to the consumer

- Spillover from other technologies – advances in power management for battery-powered applications are transferred directly to "plug-in" devices
- Increasing emphasis in efficiency community – ENERGY STAR® labeling for electronics, as well as ongoing research (EPRI, national labs, etc.)
- Collaboration with private industry – voluntary coalitions are indicative of a wholesale alignment of different interests toward the goal of efficient electronic devices

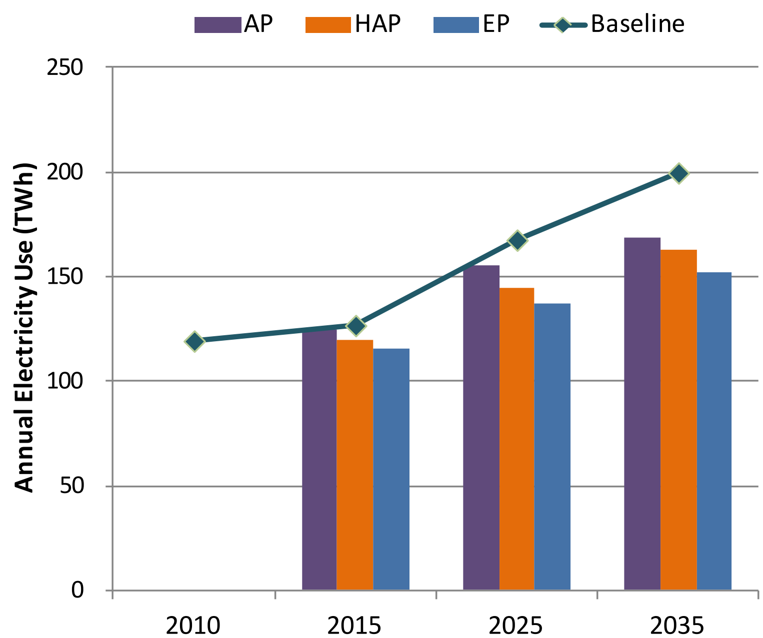

Figure 4-13
Residential Electronics Potential Estimates

Instead of traditional rebates and incentives, efficiency in residential electronics may be achieved through a close collaboration between advocates and retail suppliers of the equipment. Through changes in shelving practices, consumers can more easily find energy efficient options when shopping.

In addition through recent efficiency programs focused on TVs and PCs, there is less opportunity for energy savings compared to the previous 2009 National Study. Where all measures were cost-effective in the 2009 National Study, the use of smart power strips to reduce standby wattage does not pass anywhere throughout the forecast period, however by 2025 efficient PCs are passing in all divisions. Efficient TVs and reduction of TV standby power pass in some divisions at times throughout the forecast. Figure 4-14 shows the electronics (TVs and PCs) 2035 HAP and AP end-use savings broken out by measure, as a share of the total end-use savings.

The expected market penetration of the measures listed in Figure 4-14 will continue to be influenced by present-day efforts, such as:

- ENERGY STAR® 3.0 for color televisions effective November 2008
- Ongoing research into standby power at Lawrence Berkeley National Laboratory informing the federal rulemaking process
- ENERGY STAR® personal computers as an extension of programs being undertaken and sponsored by government and private firms, such as the 80Plus program for efficient power supplies in desktop PCs and the ClimateSavers Initiative for efficient power supplies in servers

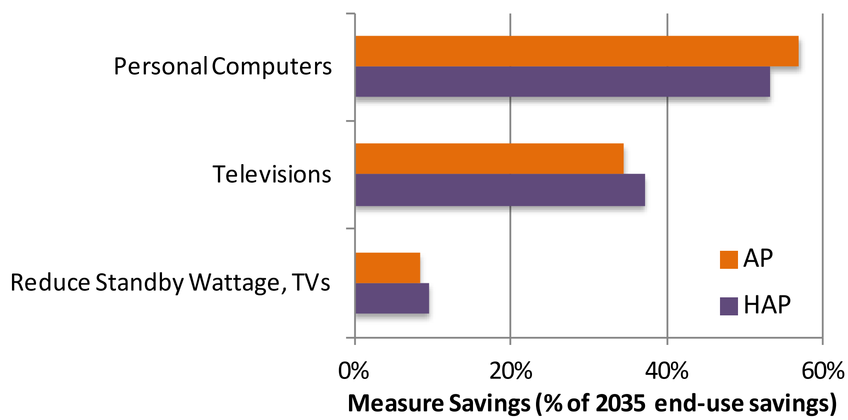

Figure 4-14
Residential Electronics Energy Savings by Measure, as a Percentage of 2035 End-Use Savings

Residential Water Heating

Figure 4-15 shows the water heating baseline along with the impacts of the economic and achievable potential in key forecast years. With updates to water heating standards requiring units with capacity greater than 55 units to have an energy factor (EF) greater than 2.0 starting in 2015 there is some reduction in potential savings. However, within the residential market where there is a mix of smaller units and units greater than 55 gallons we are able to better assess the achievable potential by screening equipment for these two categories separately. In both cases heat pumps water heaters, solar water heaters and ground-source heat pumps are considered as efficient replacement technologies in addition to resistance units when and where they are applicable.

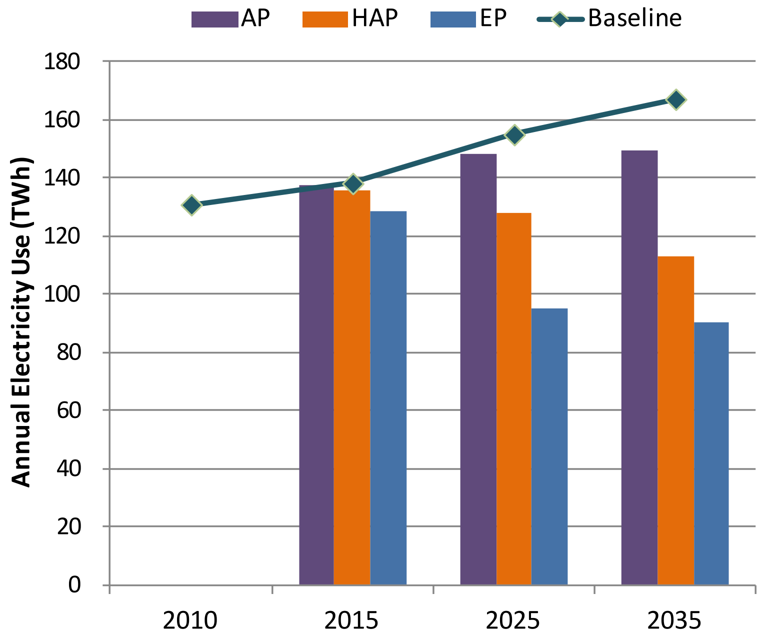

Figure 4-15
Residential Water Heating Potential Estimates

Figure 4-16 shows water heating 2035 HAP and AP end-use savings broken out by measure, as a share of the total end-use savings. Note that large water heating units with capacity greater than 55 gallons have no passing measure in 2035. Prior to the change in standard in 2015 there are units that pass in this category so there is some savings for large units early in the forecast.

There is increasing interest in optimizing water usage in the U.S. and as such secondary efficiency measures often contribute to reductions in both energy consumption and water usage. A key example of this is low-flow showerheads. In addition faucet aerators impact the amount of water used and both measures that impact water and energy consumption pass across the board producing savings throughout the forecast period.

There is a very small amount of water heating electricity savings from efficient dishwashers, however this measure passes in only a few divisions for select years.

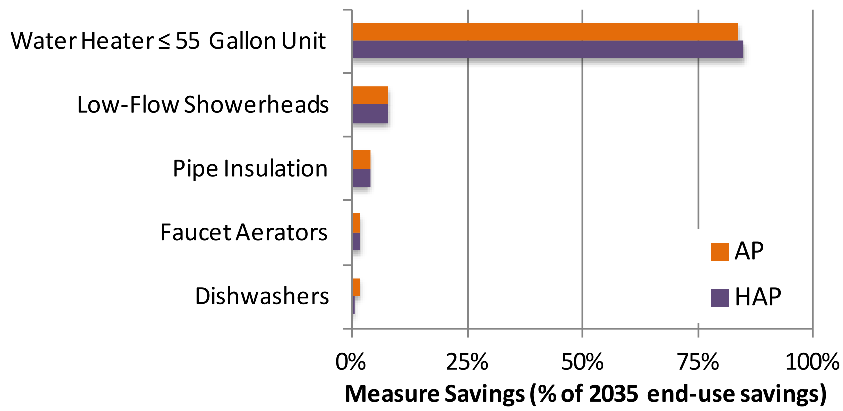

Figure 4-16
Residential Water Heating Energy Savings by Measure, as a Percentage of 2035 End-Use Savings

Residential Appliances

Figure 4-17 shows the appliances baseline along with the impacts of the economic and achievable potential in key forecast years. Through ENERGY STAR labeling and existing efficiency programs there have been opportunities to save electricity by installing efficient appliance for the last ten to twenty years. With these current efforts and additional standards coming into effect over the next five years there is less opportunity for cost-effective efficiency over the forecast period.

Appliance codes and standards coming into effect over the next five years increase baseline equipment efficiency, impacting the forecast for energy consumption out to 2035. In addition with more efficient baseline requirements there is less room for cost-effective energy efficiency. This is evident comparing the results in Figure 4-18 to the appliance-levels savings found in the 2009 National Study. Refrigerators and freezers had shown the highest level of savings, with achievable potential in all five major appliance categories. Now there are no savings found for refrigerators and clothes washers as a result of codes and standards. Although there is limited potential for energy efficiency with existing appliance technology, as technology evolves and more efficient options come to market there may be new potential for program-based energy efficiency.

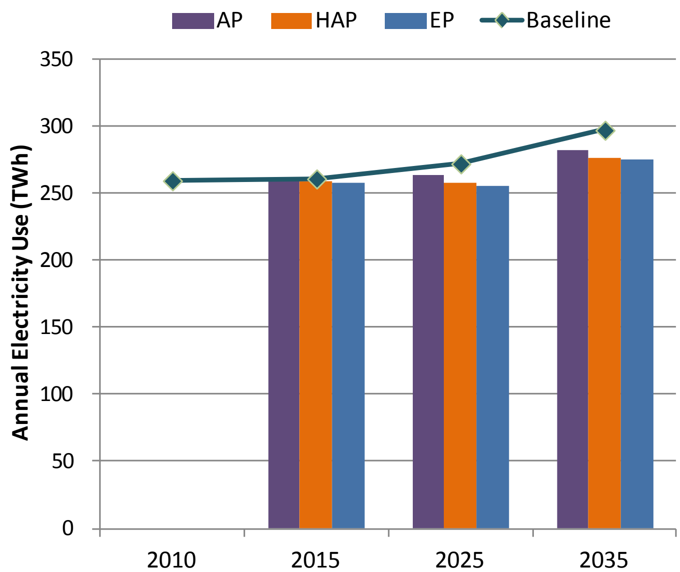

Figure 4-17
Residential Appliances Potential Estimates

Figure 4-18 shows the appliances 2035 HAP and AP end-use savings broken out by measure, as a share of the total end-use savings. Several appliances are missing from these measures and have nothing passing in 2035 and in fact refrigerators and clothes washers have no passing measures across the U.S. throughout the entire forecast period. This reflects the fact that efficiency standards are having their intended impact by reducing consumption of what people will typically install.

Dishwashers have the highest share of appliances savings in 2035 and is in the top ten end uses for achievable potential savings in the U.S. in 2035.

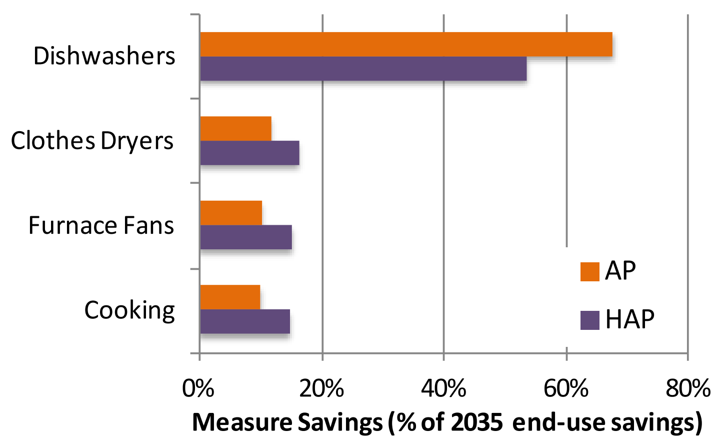

Figure 4-18
Residential Energy Savings by Appliance Type, as a Percentage of 2035 End-Use Savings

It is not uncommon for efficiency programs to incent early retirement of appliances, to allow replacement of older units with more efficient units before the existing units have failed. The early retirement of appliances has little effect on efficiency potential in the long run as modeled in this study. However the decrease in effective life of equipment will cause earlier adoption of efficient technologies, shifting potential energy savings forward in time. This may be of particular interest to utilities that have short term sales reduction requirements, and may be addressed in future scenario analysis.

Residential Lighting

Figure 4-19 shows the residential lighting baseline along with the impacts of the economic and achievable potential in key forecast years. Early in the forecast before the full effects of the EISA 2007 legislation, there is significant savings available. However, later in the forecast the potential for savings in residential lighting decreases. Again this demonstrates the intended outcome of EISA 2007 in lower baseline energy consumption. The efficacy requirements of EISA 2007 have spurred innovation in screw-in lighting technologies so that consumers now have options beyond the CFL when shopping for efficient lighting, and technologies are expected to continue to evolve.

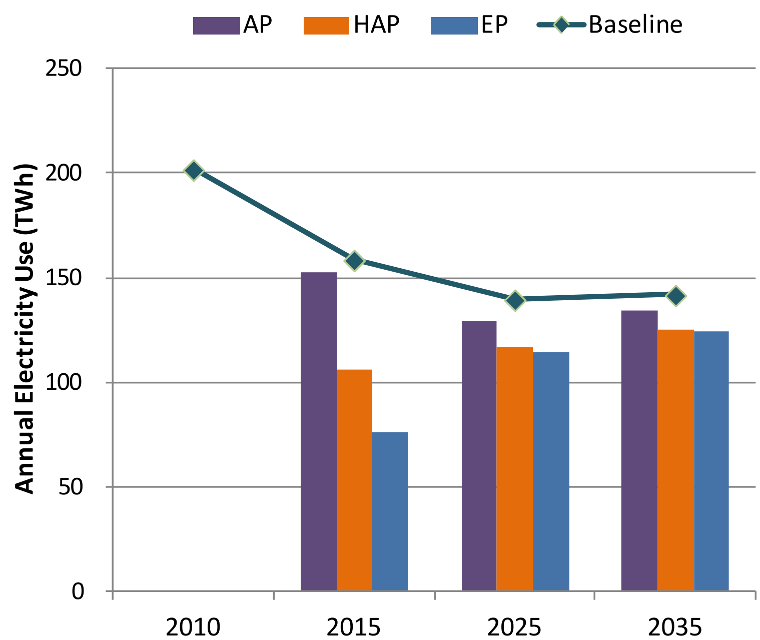

Figure 4-19
Residential Lighting Potential Estimates

Figure 4-20 shows the lighting 2035 HAP and AP end-use savings broken out by screw-in lighting and linear fluorescent lighting, as a share of the total end-use savings. Over the forecast period residential lighting has an achievable potential energy savings of 233 TWh. The majority, 87% of the savings, is achieved through efficient screw-in lighting. The base technology for screw-in lighting is a hybrid of CFL technology and incandescent-equivalent technology. To begin with 60W incandescent are included, with the first round of EISA 2007 efficacy this moves to halogen, and with the second round of EISA 2007 a technology that meets the efficacy requirements comes into the mix. Over time the share of CFLs grows, and the "incandescent" portion of the stock becomes more efficient. The combined effect is that over time as the baseline becomes more efficient, there is less opportunity for marginal cost-effective energy savings.

Early in the forecast the passing technology for screw-in lighting is LED, however as the 2020 EISA requirements come into effect the marginal savings from LED technology no longer outweigh the marginal costs. Therefore in most cases a CFL becomes the winning technology around 2023 through the end of the forecast. The long life of the LEDs allows the savings achieved when they are installed early on to linger throughout.

The primary passing measure for linear fluorescents is linear LED, which is a one-to-one tube replacement for existing T8s and T12s. There is no need for changing ballasts or fixtures. Because the 2035 achievable savings are higher for the passing linear fluorescent measure than the passing screw-in measure, the relative share of end-use savings is higher for linear fluorescent.

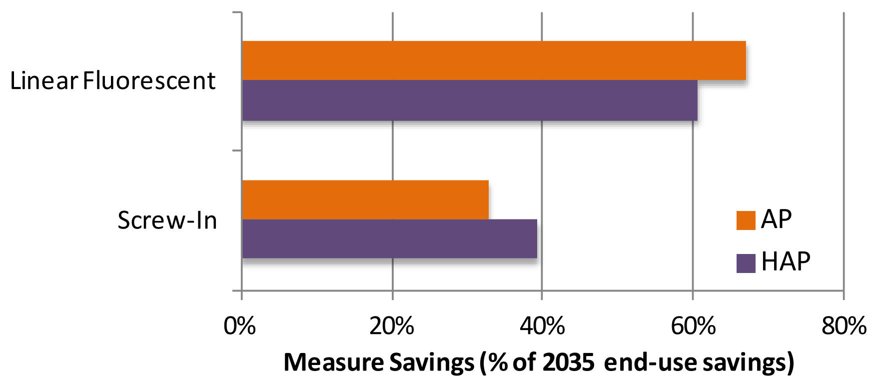

Figure 4-20
Residential Lighting Energy Savings by Measure, as a Percentage of 2035 End-Use Savings

Residential Savings Potential by Building Segment

Savings in the residential sector are calculated relative to the bottom-up forecasts, as such the savings by type of home within the residential sector are taken relative to the *AEO2012* adjusted baseline. All housing segment results are presented as a percentage of a baseline since in absolute terms the total sum of the housing-level results may not match the sum of the division-level results.

All building segment results are presented as a percentage of a baseline since in absolute terms the total sum of the building-level results may not match the sum of the division-level results.

Figure 4-21 shows the 2012 and 2035 housing segment forecast broken out by share of total residential consumption. The impacts of 2035 high achievable and achievable potential are also shown relative the 2035 baseline.

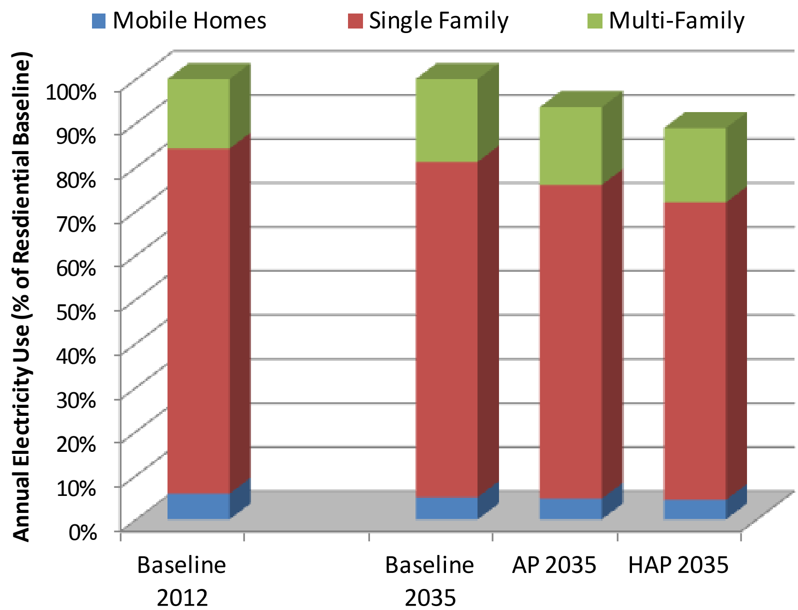

Figure 4-21
Residential Sector Energy Baseline Shares and Achievable Potentials by Housing Segment

The savings in the three housing as a percentage of the residential baseline are shown in Figure 4-22. The share of savings in the single family is higher than multi-family and mobile homes, which is to be not surprising since single family homes comprise the largest share of the residential baseline.

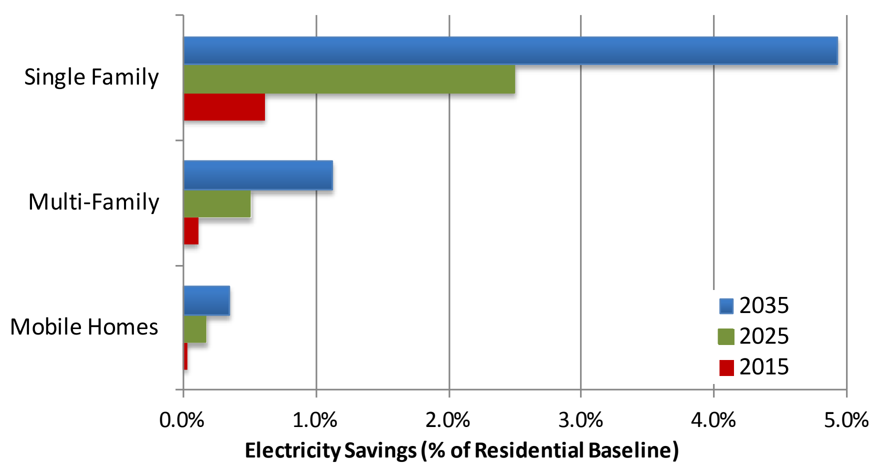

Figure 4-22
Residential Achievable Potential Energy Savings by Housing Segment, as a Percent of Residential Baseline

The savings in each segment relative to the segment baseline ranges from 6% in multi-family to 7% in mobile homes with single family in between. There is not a significant difference in the potential savings from a percentage standpoint although the absolute savings in the single family portion will be higher.

Table 4-2 presents the top three end uses in each segment in terms of their 2035 achievable savings relative to each segment's baseline. Consumer electronics and water heating are top in both the single family and multi-family segments.

Mobile homes are slightly different where there are opportunities for heat pumps to replace existing electric heating and central AC units. The passing measure in this case is ground-source heat pumps throughout most of the forecast. Although this may not be a feasible solution for a single mobile home, a ground-source heat pump with a common ground-exchange loop may be applied to several homes in the same proximity.

Table 4-2
Top Three Residential End Uses for 2035 Achievable Potential, by Housing Segment

Segment	End Use	% of Baseline
Mobile Homes	Water Heating	1.6%
	Heat Pump (replacing non-HP heat and central AC)	1.3%
	Computers	0.8%
Single Family	Computers	1.3%
	Televisions	0.9%
	Water Heating	0.9%
Multi-Family	Computers	1.2%
	Water Heating	1.0%
	Televisions	0.9%

Note: HP = heat pump; AC = air conditioning

Commercial Sector

Energy efficiency efforts targeting the commercial sector continue to expand, with opportunities ranging from advanced building controls systems to lighting retrofits. Figure 4-23 presents the energy savings opportunities assessed, compared to the original baseline forecast. The baseline CAGR between 2012 and 2035 is 1.21%, the achievable potential reduces this CAGR to 0.41%. Under an ideal set of conditions conducive to energy efficiency programs, this growth rate can be reduced to as low as 0.33% per year.

Over time the achievable potentials approach the economic potential such that by 2035 the forecast with achievable potential is only about 3% higher than the forecast with economic potential. This illustrates the impacts of reduced market and program barriers over time.

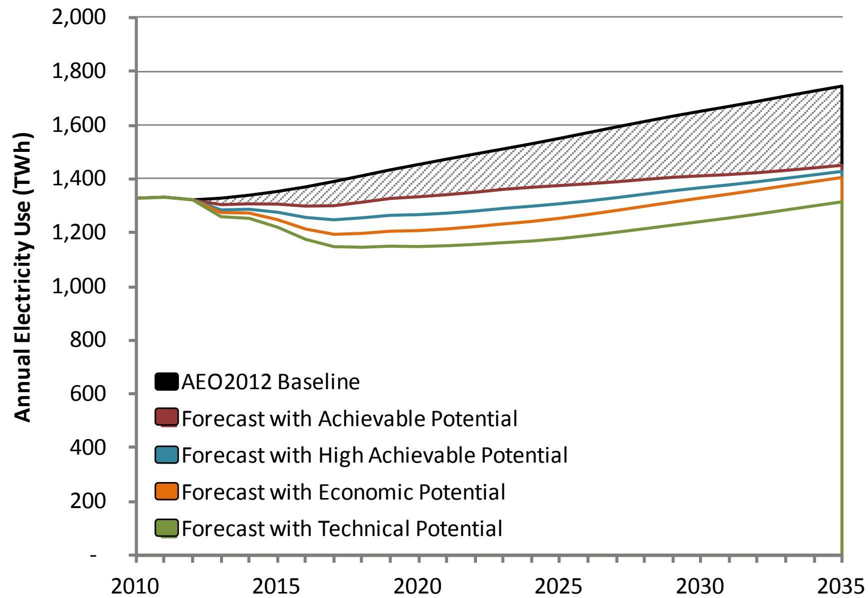

Figure 4-23
Commercial Energy Efficiency Potentials in Context of the Baseline Forecast

Figure 4-24 illustrates residential electricity use in the bookend years of this study and shows the 2035 impacts of achievable potential (AP) and high achievable potential (HAP) energy reductions at the end-use level.

Unlike the residential sector where EISA 2007 obviated the need for aggressive efficiency efforts in residential lighting, there are still significant opportunities for energy savings in the commercial sector where lighting is primarily provided by linear fluorescents. In the baseline lighting has compound annual growth of 0.6% and with achievable savings incorporated this is reduced to a -3.1% CAGR.

Office equipment has baseline annual growth of 2.0%, reduced to 0.5% annual growth with achievable potential. These two areas offer significant opportunities for energy savings in the commercial sector.

Heat pump savings are also significant relative to the end-use baseline, however the baseline is a small fraction of commercial consumption therefore the absolute savings are relatively small.

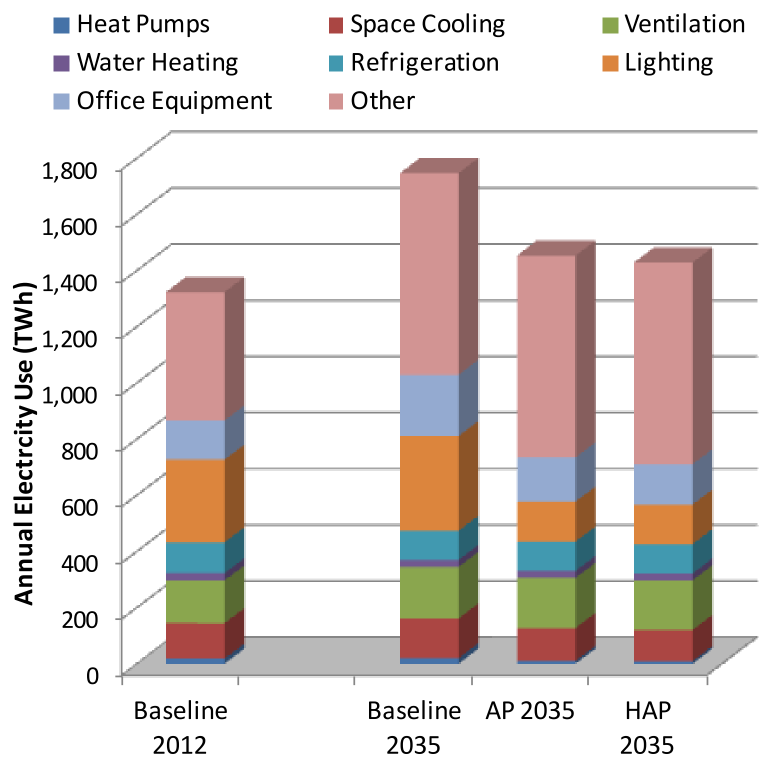

Figure 4-24
Commercial Sector Energy Baseline and Potential Savings by End Use

Note: Other electric space heating not provided by heat pumps is captured in other.

Commercial Savings in Terms of Electric Intensity

Figure 4-25 presents the same baseline and achievable savings information for commercial consumption, normalized on a per square foot basis. The electric energy intensity in the baseline is 17 kWh per square foot in 2035, reduced to 14.1 kWh per square foot with achievable potential incorporated.

Savings potential in space cooling is more pronounced when considering intensity. The average annual growth in intensity in the baseline is -0.5% which reduces to -1.3% with achievable potential included.

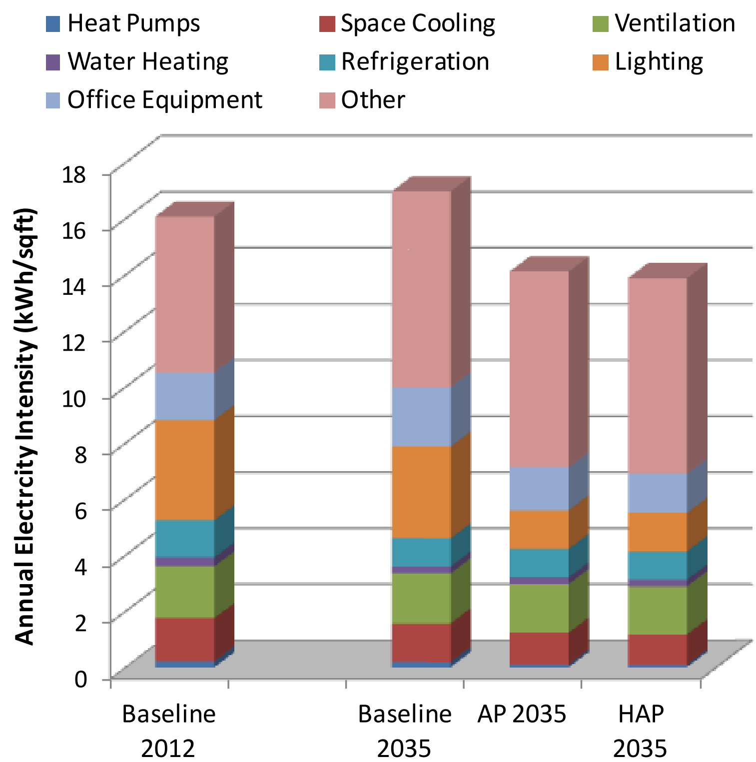

Figure 4-25
Commercial Sector Energy Intensity Baseline and Achievable Potentials by End Use

Note: Other electric space heating not provided by heat pumps is captured in other.

Commercial Savings Potential by End Use

Figure 4-26 shows the end-use achievable savings potential for key forecast years. As previously discussed, lighting, office equipment and space cooling are the highest achievers. Each of these end uses is discussed below in detail.

HVAC (cooling, heat pumps and ventilations) accounts for about 39 TWh of achievable energy savings in 2035, about 13% of the commercial achievable potential. Although there is tremendous savings potential in HVAC – both in terms of energy and peak demand – economic factors and equipment performance limit the achievable potential. It is imperative that research efforts in HVAC efficiency focus on not just energy savings but also on deployment to help drive the costs down. As part of EPRI's ongoing energy efficiency research, market barriers such as this are identified and strategies employed to overcome these barriers to increase achievable energy savings.

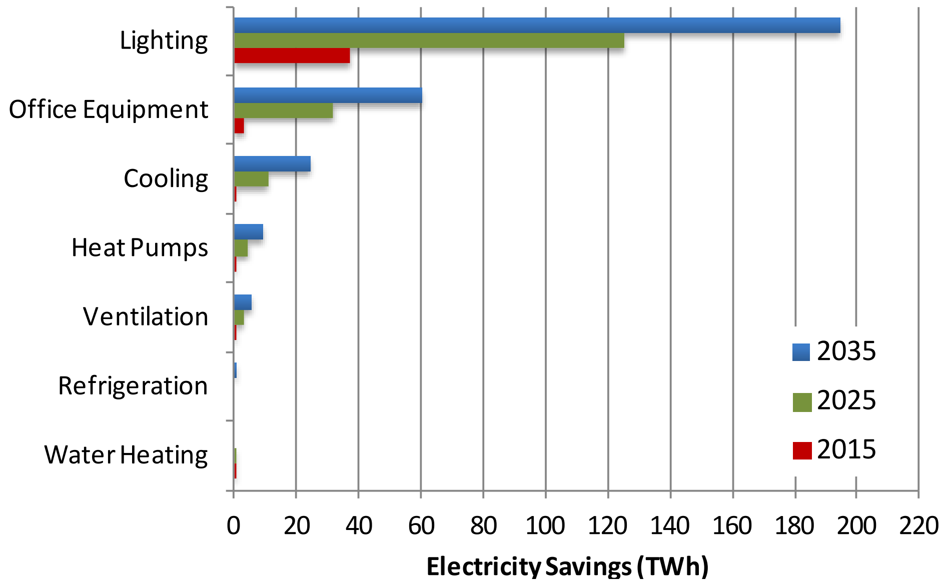

Figure 4-26
Commercial Realistic Achievable Potential by End Use

Refrigeration has a small amount of potential as one measure – floating head pressure controls – begins passing in the South Atlantic and the Pacific in 2031 resulting in small savings in 2035.

In the case of water heating there are efficient units passing in all divisions except West North Central and East North Central (both in the Midwest) from 2010 to 2014. It is assumed that all water heating in the commercial sector is provided by large units (> 55 gallons), therefore once the new water heating standard comes into effect in 2015 making an energy factor of 2.0 the minimum available, no units pass. There is a little savings early on from the units replaced in 2013 and 2014 which phases out as those units turn over throughout the rest of the forecast. I

Commercial Lighting

Figure 4-27 shows the commercial lighting baseline along with the impacts of the economic and achievable potential in key forecast years. Based on CBECS data indoor lighting is on average about 95% of baseline lighting consumption. Linear fluorescent consumption is about two thirds of this, and screw-in lighting is about one fifth. The remaining portion of indoor lighting is assumed to be high-intensity discharge (HID) lighting. In addition to treating these three categories of indoor lighting, this study also looks at outdoor street and area lighting.

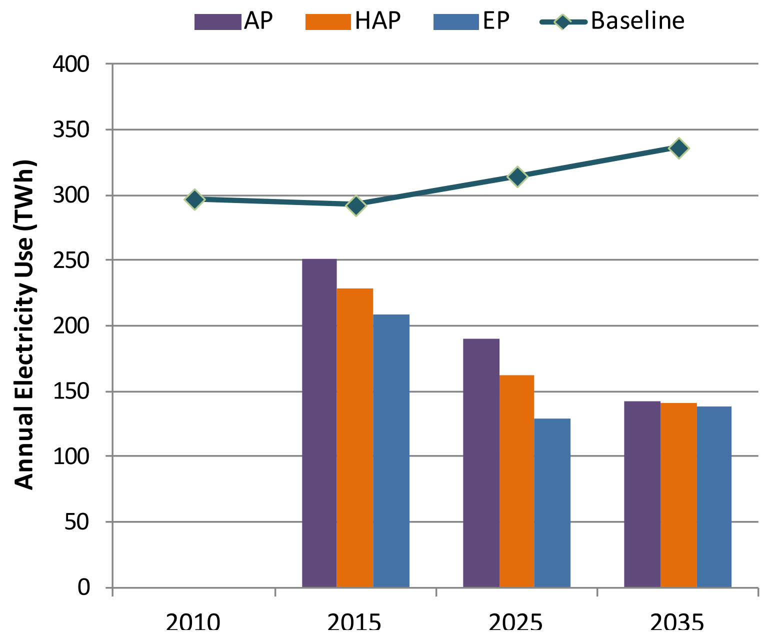

Figure 4-27
Commercial Lighting Potential Estimates

Figure 4-28 shows the lighting 2035 HAP and AP end-use savings broken out by linear fluorescent, HID, outdoor and screw-in lighting as a share of the total end-use savings. Older building with existing fixture and ballast technology presents a significant opportunity for savings through retrofit. Over the forecast period linear fluorescent savings account for almost 80% of achievable savings available in indoor lighting.

Commercial screw-in lighting sees similar dynamics as those discussed for the residential sector. Early in the forecast LED passes the economic screen but as the baseline gets more efficient the passing technology moves to CFL. As the baseline technology becomes more efficient with the 2020 EISA efficacy requirements, there is a period of several years where no technologies pass. As the cost of technologies is reduced beginning in 2021, the CFL is re-introduced as a passing measures in all divisions except the East North Central by 2029.

Induction technology has the potential for cost-effective HID savings in all divisions across the forecast period, and accounts for about 9% of commercial achievable energy savings over the forecast period.

With higher usage in terms of operating hours and per unit consumption in the commercial sector, a full LED fixture replacement passes in the early years. When the future technology – an unspecified technology with higher efficiency – is introduced in 2020 this is immediately cost effective and passes in all divisions throughout the rest of the forecast. This future technology is assumed to have an efficacy of about 110 lumens per watt and provides 65% energy savings over the baseline linear fluorescent technology.

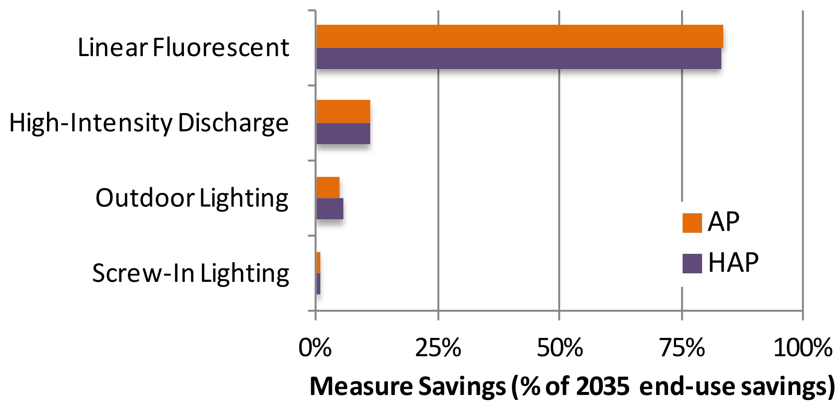

Figure 4-28
Commercial Energy Savings by Measure, as a Percentage of 2035 End-Use Savings

Outdoor street and area lighting is also addressed and accounts for about 3% of commercial achievable potential in 2035, and 10% of the cumulative savings. This category is treated differently than other commercial end uses and technologies were not screened for cost-effectiveness. The stock is split between two baseline technologies, 250 W metal halide fixtures and 400 W high-pressure sodium/metal halide fixtures. The replacement technologies are LED fixtures with 60 W and 158 W respectively. These are assumed to provide the same amount of useful light output as the technology they are replacing, and were rolled in as the existing technologies turned over.

Some level of lighting controls is included in the commercial lighting measures through dimmable technologies. However, additional savings may be achieved considering application of multiple lighting control schemes not considered in this study. The savings achieved naturally through lighting controls is expected to evolve as states consider adopting building efficiency codes with allowances for lighting controls such as ASHRAE 90.1-2010.

Commercial Office Equipment

Figure 4-29 shows the office equipment baseline along with the impacts of the economic and achievable potential in key forecast years. Similar to the market for residential electronics in many ways, commercial office equipment is expected to account for a growing portion of electricity consumption over the next 22 years. This trend is amplified by several factors:

- Shift toward service-based economy
- Increased digitalization
- Rapid technological development
- Expanding performance demands

The baseline for office equipment has an average annual growth of 2%, the impact of the achievable potential almost levels growth reducing the CAGR between 2012 and 2035 to 0.5%.

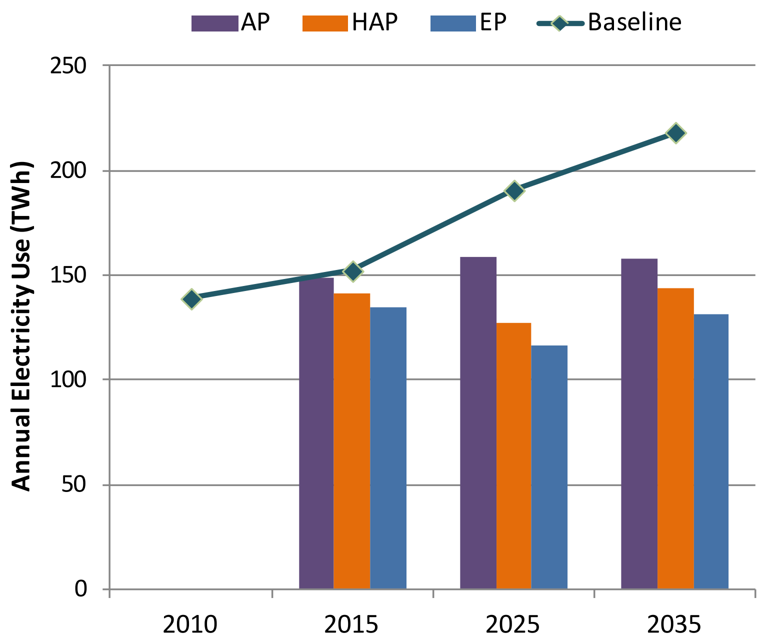

Figure 4-29
Commercial Office Equipment Potential Estimates

Figure 4-30 shows the office equipment 2035 HAP and AP end-use savings broken out by technology category, as a share of the total end-use savings.

For the most part the passing measures are all ENERGY STAR, with measures passing in all divisions across the entire forecast period.

Most of the savings in these categories is possible through increased efficiency in power conversion. All of these items require conversion of AC power to DC and reducing losses in the electronics provides opportunities for savings. In addition, power management provides opportunities for savings if consumption is reduced or eliminated when the equipment is idle.

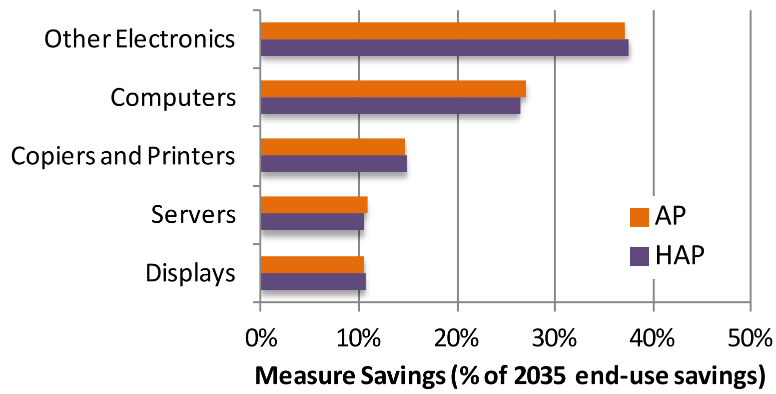

Figure 4-30
Commercial Office Equipment Energy Savings by Measure

Commercial Cooling

Commercial cooling is expected to grow slightly out to 2035 and incorporating potential savings leads to a decline in cooling consumption as shown in Figure 4-31.

The commercial space cooling baseline includes chillers, central AC and other electric cooling. Other electric cooling has no efficiency measures applied and therefore no savings potential.

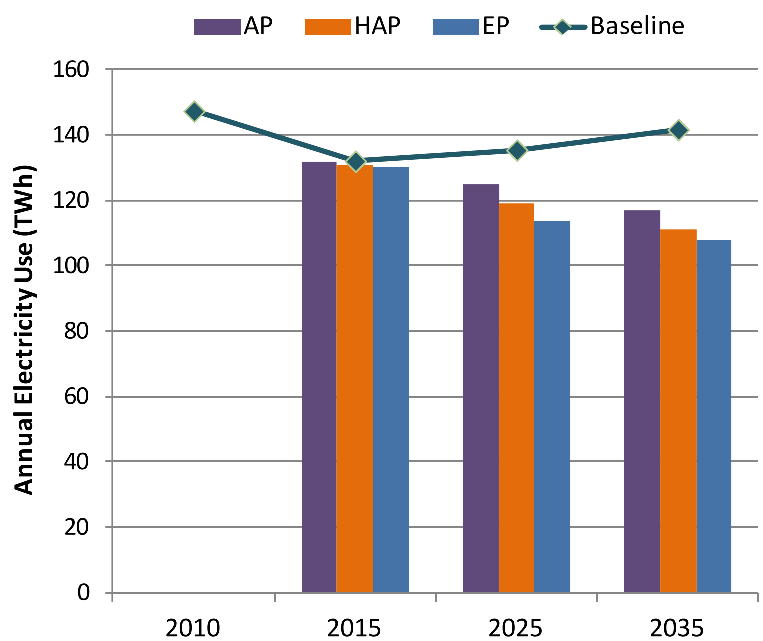

Figure 4-31
Commercial Cooling Potential Estimates

Figure 4-32 shows the space cooling 2035 HAP and AP end-use savings broken out by measure, as a share of the total end-use savings. As a whole, space cooling accounts for 8% of achievable energy savings potential in 2035. Similar to the residential sector, commercial cooling also has savings attributable to equipment upgrades, improved controls, and shell measures.

In terms of more efficient space cooling equipment, there are opportunities for buildings using central air conditioning and for larger buildings that use chillers for space cooling.

Central AC units only pass in the five divisions in the South Census region (South Atlantic, Florida, East South Central, West South Central, and Texas). Several shell measures provide a little savings for buildings employing central AC cooling. Again these measures pass only in the South Census region where the intensity of central AC space cooling is higher.

The use of energy management systems (EMS) and variable air volume systems in larger buildings with chillers off provide additional space cooling savings. EMS pass across all divisions by the end of the forecast, whereas secondary chiller measures tend to pass primarily in the South divisions. Compared to Central AC, chiller measures pass a little more widely with opportunities more prevalent in the Mountain divisions and the Middle Atlantic.

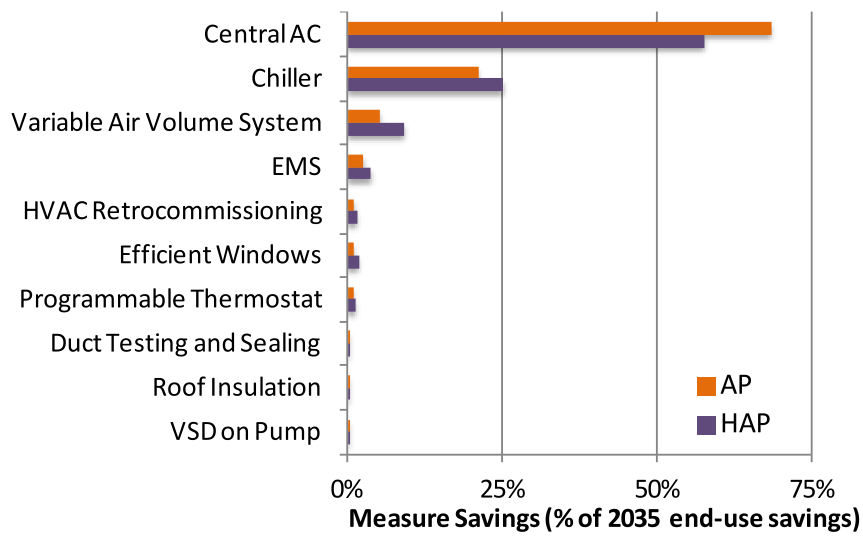

Figure 4-32
Commercial Cooling Energy Savings by Measure

As codes and standards related to HVAC equipment and building efficiency change, the achievable potential will evolve. In particular as states consider adopting more stringent building efficiency codes such as ASHRAE 90.1-2010, we will continue to see change in the level of programmatic energy savings that may be achieved.

Commercial Heat Pumps

Heat pumps are the fourth highest end-use for achievable potential savings comprising 3% of the 2035 achievable potential savings in the commercial sector. This is significant considering that in 2035 heat pumps for space heating and cooling only account for 1% of baseline usage. Figure 4-33 shows the heat pump baseline along with the impacts of the economic and achievable potential in key forecast years.

There is little increase in heat pump consumption between 2015 and 2035, so that with the efficiency savings potential consumption is forecast to decline with a CAGR of -2.4%.

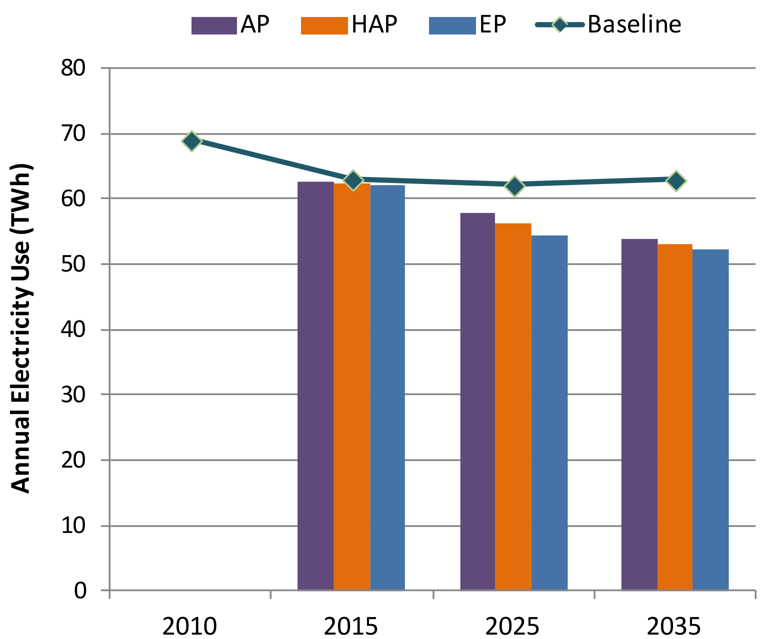

Figure 4-33
Commercial Heat Pump Potential Estimates

Figure 4-34 shows the lighting 2035 HAP and AP end-use savings broken out by heat pump measures, as a share of the total end-use savings. Replacing existing heat pumps with more efficient units presents the greatest opportunity for achievable energy savings. Efficient heat pumps pass across all divisions throughout the forecast. The Mountain divisions are the first place where the additional building control and shell measures pass, but aside from heat pump units none of the other measures pass as uniformly.

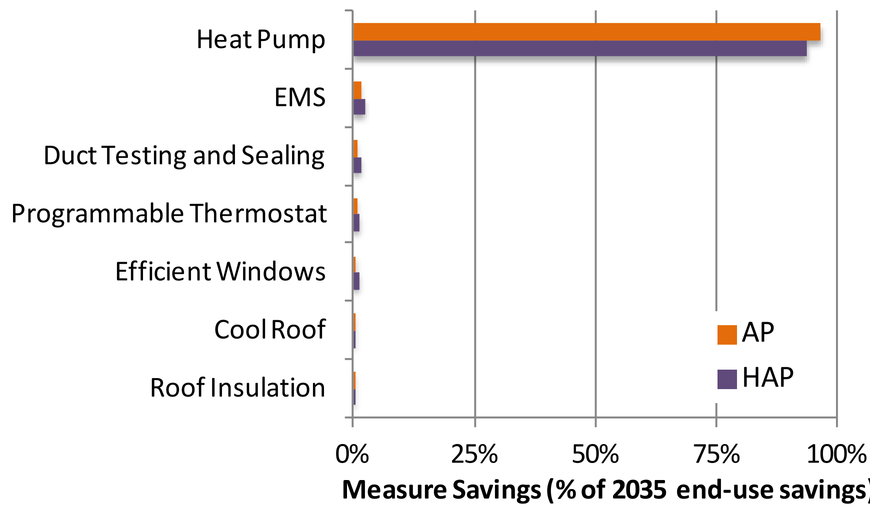

Figure 4-34
Commercial Heat Pump Energy Savings by Measure

Commercial Savings by Building Type

Similar to the residential sector, savings in the commercial sector are calculated relative to the bottom-up forecasts; as such the savings by building type within the commercial sector are taken relative to the *AEO2012* adjusted baseline. All building segment results are presented as a percentage of a baseline since in absolute terms the total sum of the building-level results may not match the sum of the division-level results.

Figure 4-35 shows the 2012 and 2035 housing segment forecast broken out by share of total commercial consumption. The impacts of 2035 high achievable and achievable potential are also shown relative the 2035 baseline. The greatest reductions in terms of building-level forecast are found in small offices, followed by large offices and warehouses.

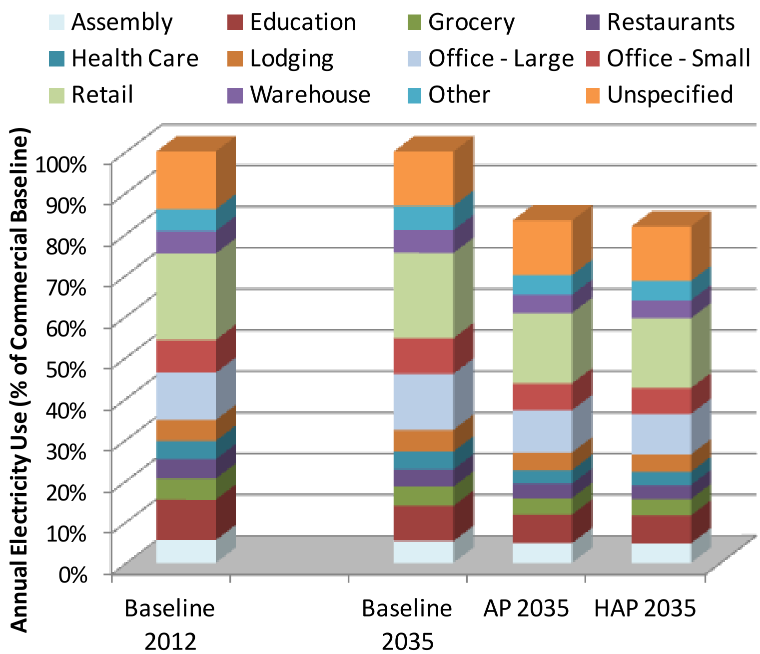

Figure 4-35
Commercial Sector Energy Baseline Shares and Achievable Potentials by Building Segment

Figure 4-36 ranks the building types by their reduction in the total commercial baseline; from that perspective retail and large office space present the greatest opportunity for energy savings. Although retail space is not at the top of the list in terms of savings relative to the building baseline, it is the highest consuming building segment and therefore has the highest potential savings relative to the total commercial baseline.

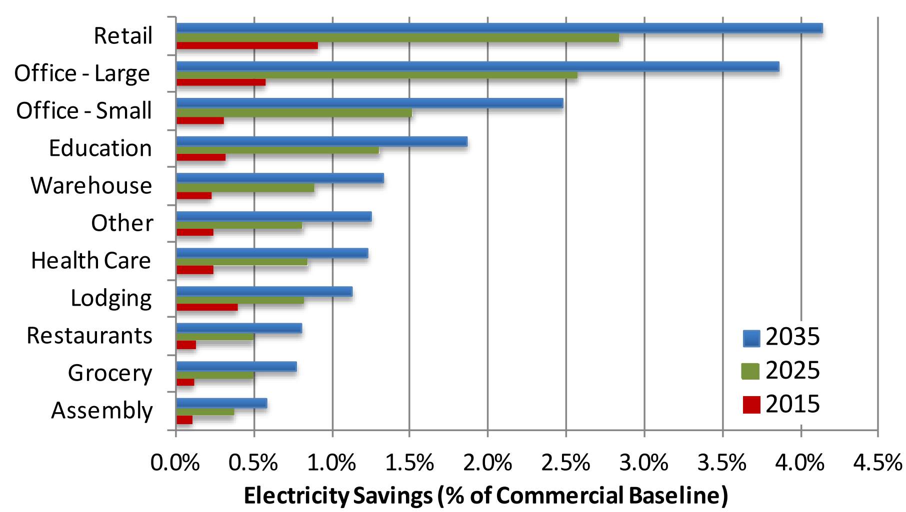

Figure 4-36
Commercial Achievable Potential Energy Savings by Building Segment, as a Percent of Commercial Baseline

To get some insight into the potential available within the building segments Table 4-3 has the top three end uses and their 2035 achievable savings as a share of the building segment baseline. Indoor lighting is in the top three for all segments and is number one in all except restaurants where central AC marginally has the highest savings.

Not surprisingly miscellaneous office equipment and computer present significant savings opportunities in the office segments.

Table 4-3
Top Three Commercial End Uses for 2035 Achievable Potential, by Building Segment

Division	End Use	% of Baseline
Assembly	Indoor Lighting	4.5%
	Heating and Cooling - Heat Pump	1.5%
	Ventilation	0.8%
Education	Indoor Lighting	10.9%
	Personal Computers	2.2%
	Heating and Cooling - Heat Pump	1.7%
Grocery	Indoor Lighting	9.5%
	Cooling - Central AC	2.2%
	Heating and Cooling - Heat Pump	0.7%
Restaurants	Cooling - Central AC	6.5%
	Indoor Lighting	6.1%
	Heating and Cooling - Heat Pump	1.4%
Health Care	Indoor Lighting	17.9%
	Cooling - Central AC	1.1%
	Personal Computers	1.0%
Lodging	Indoor Lighting	13.4%
	Other Electronics	1.4%
	Outdoor Lighting	0.7%
Office - Large	Indoor Lighting	12.6%
	Personal Computers	2.8%
	Other Electronics	2.7%
Office - Small	Indoor Lighting	11.3%
	Other Electronics	4.0%
	Personal Computers	3.0%

Table 4-3 (continued)
Top Three Commercial End Uses for 2035 Achievable Potential, by Building Segment

Division	End Use	% of Baseline
Retail	Indoor Lighting	14.0%
	Other Electronics	0.9%
	Outdoor Lighting	0.8%
Warehouse	Indoor Lighting	15.1%
	Outdoor Lighting	2.5%
	Other Electronics	1.4%
Other	Indoor Lighting	12.8%
	Other Electronics	1.8%
	Personal Computers	0.8%

Industrial Sector

While the residential and commercial sectors have been studied in detail and targeted through a range of DSM efforts over the past several decades, demand-side analysis of the industrial sector has traditionally maintained a more general approach. This is largely due to the highly specialized, complex and widely diverse energy-consuming systems and processes employed at industrial facilities, ranging from chemical production to metal reprocessing to production of specialized aerospace technologies. Without the detailed, almost site-specific data that extend beyond the scope of this study, it is necessary to analyze energy use in industrial applications at a generalized level, following the approach applied in most comparable forecasts.

Figure 4-38 presents the economic and achievable potential in the context of the baseline forecast. No technical potential is evaluated for the industrial sector.

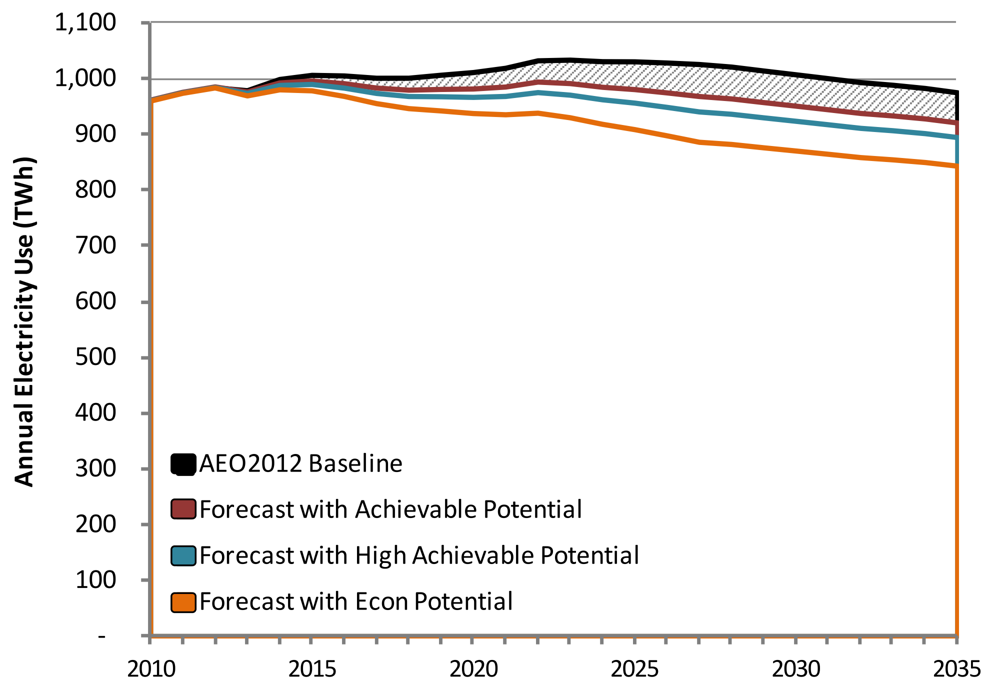

Figure 4-37
Industrial Energy Efficiency Potentials in Context of the Baseline Forecast

Industrial electricity use is forecast to decline slightly from 2012 to 2035 with annual growth of -0.04. Energy savings in the achievable potential decreases the annual growth to -0.29%.

Figure 4-38 shows the annual electricity use in 2012 and 2035 broken out by process; 2035 consumption is also shown with the impacts of the high achievable and achievable potential. The biggest reduction in end-use consumption is through industrial facilities and pumps.

Industrial facilities includes facility HVAC and lighting and therefore presents savings opportunities similar to space conditioning and lighting in the residential and commercial sectors.

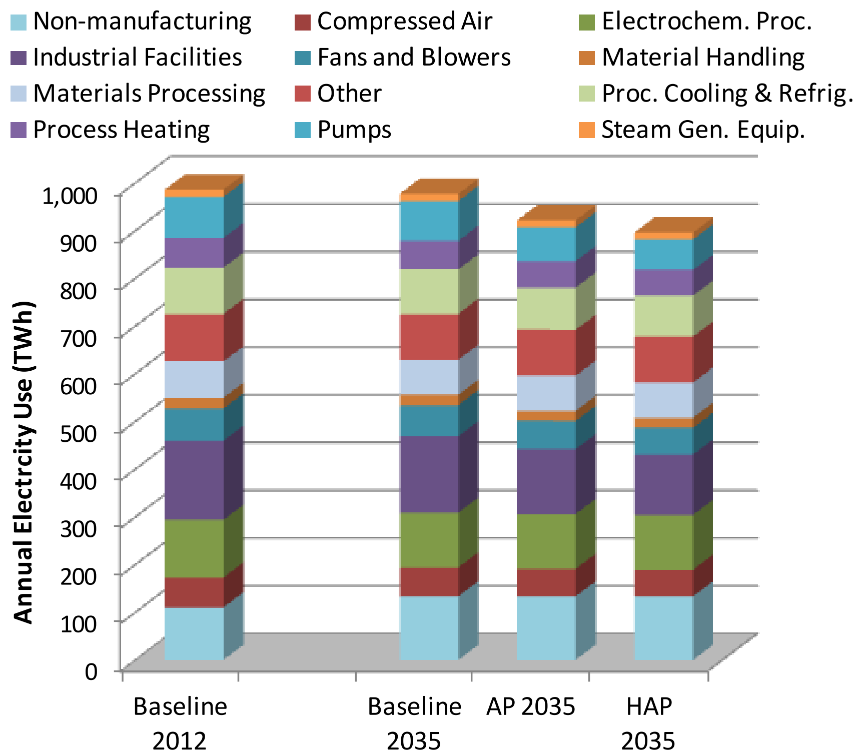

Figure 4-38
Industrial Sector Energy Baseline and Achievable Potentials by Process

Industrial Savings in Terms of Electric Intensity

Figure 4-39 shows industrial electricity use normalized on a per employee by process. Although absolute consumption in industrial reduces slightly over the forecast, the intensity increases over the period. As the consumption by end use decreases, the number of employees is also forecast to decrease but at a faster rate, outpacing the decrease in consumption and leading to an increase in intensity.

With achievable potential savings in corporate intensity is still forecast to increase in all processes but at a slower rate. In the extreme, the annual growth for industrial facilities and pumps decrease from 0.9% to 0.2%.

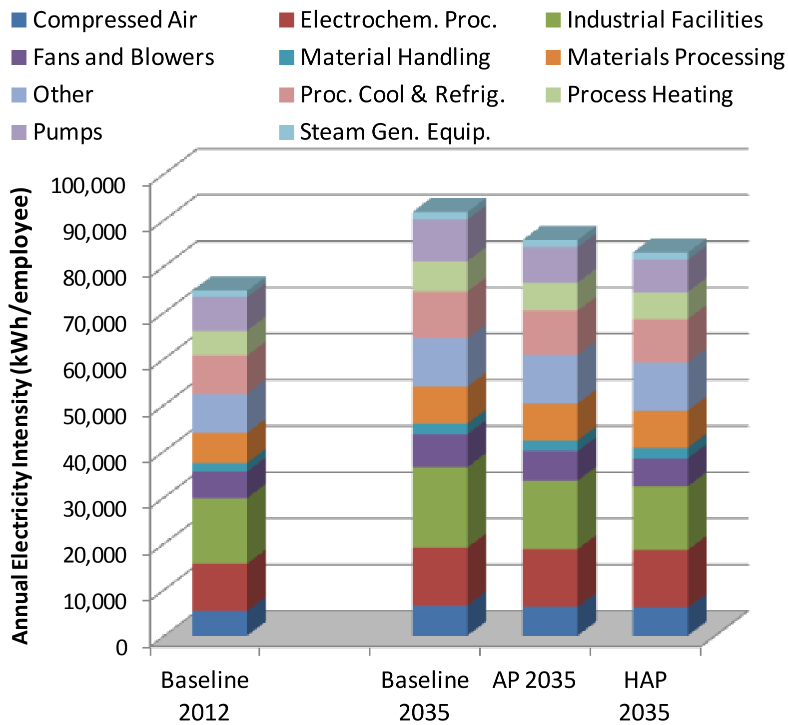

Figure 4-39
Industrial Sector Energy Intensity Baseline and Achievable Potentials by Process

Industrial Savings Potential by Process

Figure 4-40 ranks the achievable potential for industrial processes by their 2035 achievable potential, with industrial facilities providing the highest energy savings throughout the forecast.

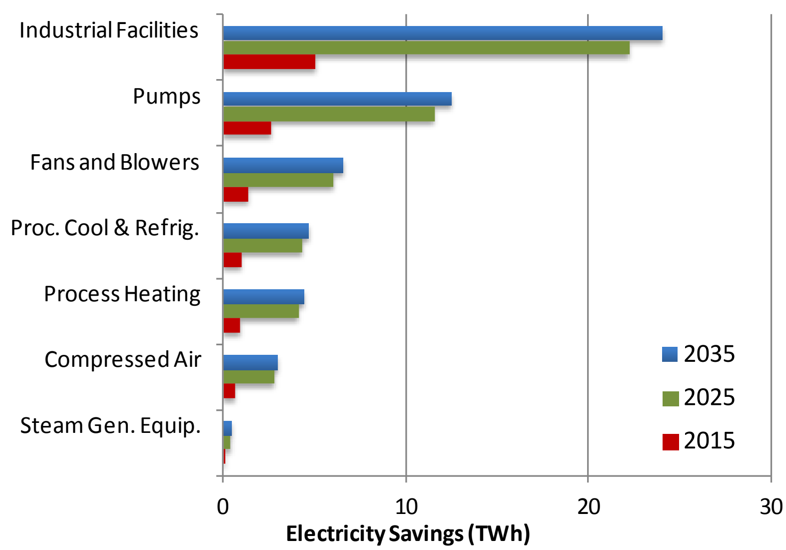

Figure 4-40
Industrial Achievable Potential by Process

Industrial Facilities

Taking a closer look at the savings in industrial facilities consumption, Figure 4-41 shows the baseline along with the impacts of the economic and achievable potential in key forecast years. The achievable potential for savings in 2035 is about 24 TWh, or 15% of baseline consumption. This category represents potential for savings across manufacturing segments since for the most part all facilities require HVAC or lighting of some sort.

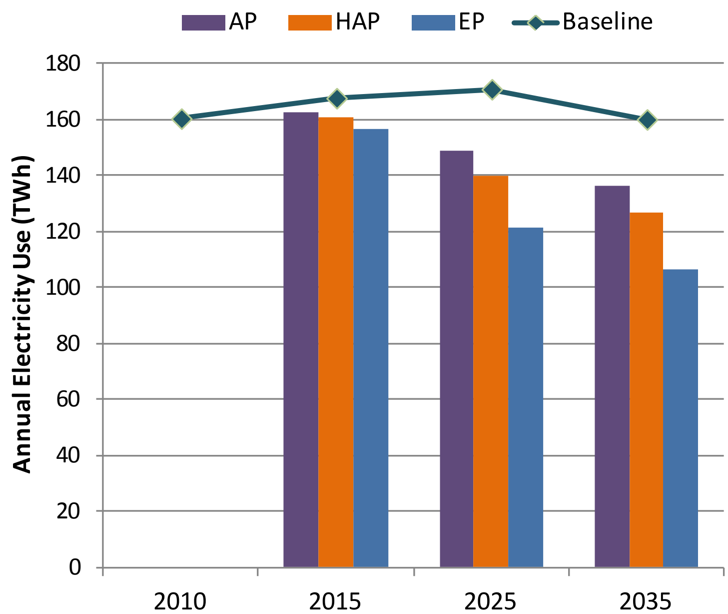

Figure 4-41
Industrial Facilities Potential Estimates

Industrial Pumps

Figure 4-42 shows the industrial pumps baseline along with the impacts of the economic and achievable potential in key forecast years. Efficiency in this category also presents the potential for 15% savings over baseline consumption in 2035, in absolute terms 12 TWh.

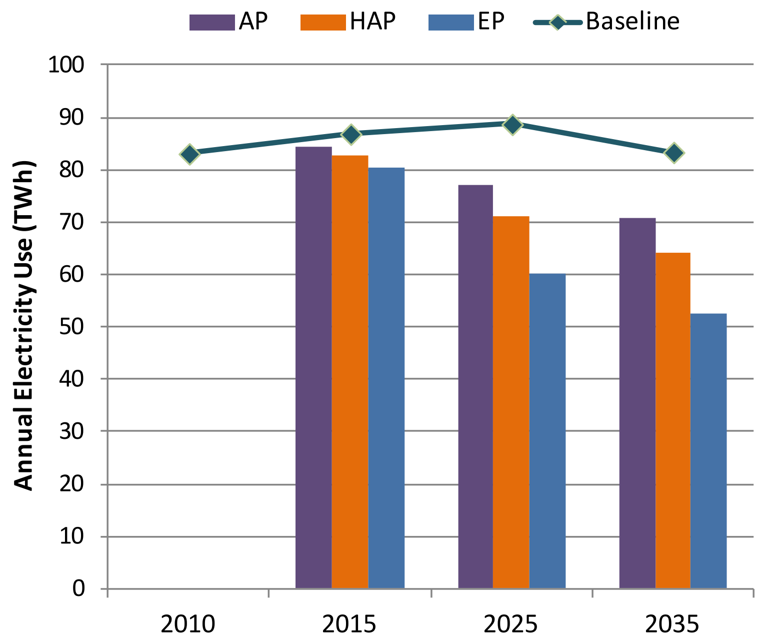

Figure 4-42
Industrial Pumps Potential Estimates

Industrial Savings Potential by NAICS Code

The achievable energy savings in industrial is ranked by NAICS code in Figure 4-43. Primary metals (NAICS code 331) and chemicals and allied products (NAICS code 325) have the highest achievable potential, not surprisingly they also have the highest consumption (chemicals and allied products has higher consumption than primary metals). Although the absolute savings are the highest in the two manufacturing segments, they both save only about 6% over their respective baseline consumption.

There are five divisions with savings of 14% over their baselines in 2035:

- 313-316 Clothing
- 323 Printing
- 334 Computer Equipment
- 334 Appliance Manufacturing
- 339 Miscellaneous Manufacturing

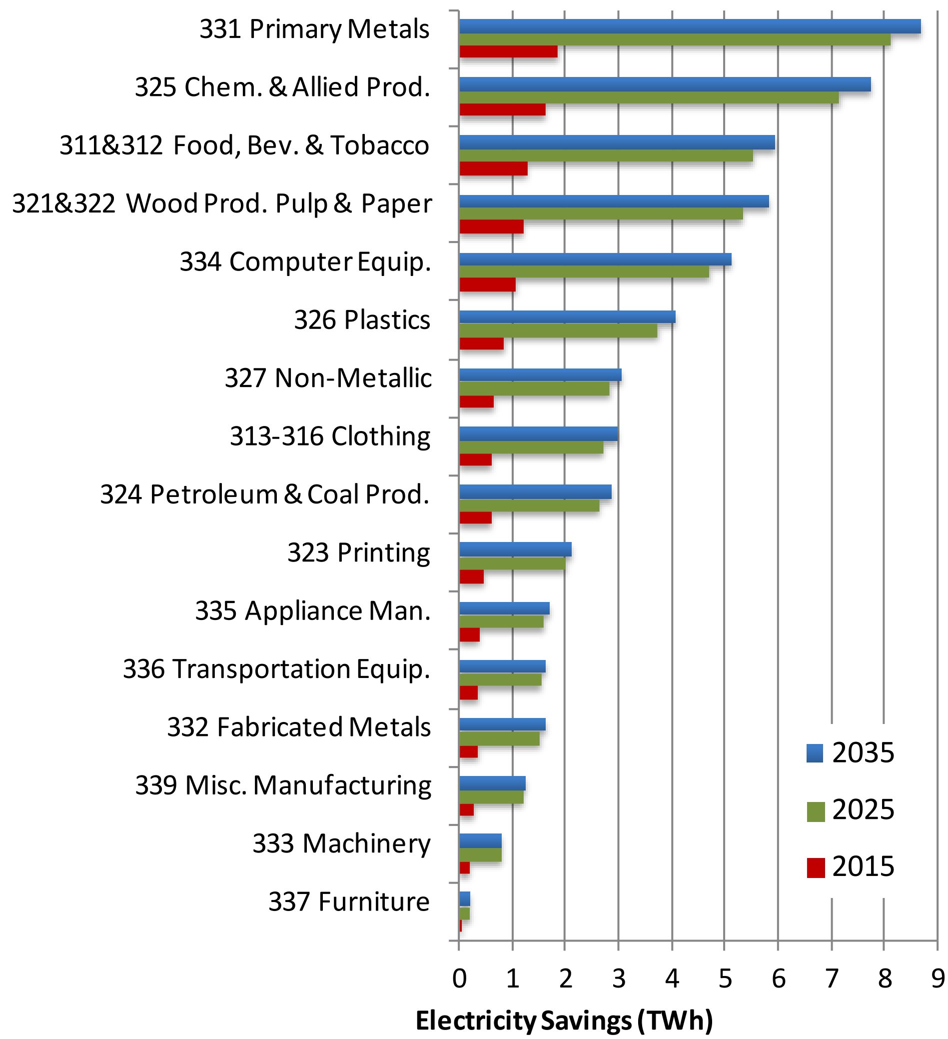

Figure 4-43
Industrial Achievable Potential by NAICS Code

Table 4-4 shows the top three processes for 2035 achievable savings by NAICS code and lends some insight into the potential for savings in the divisions discussed previously. Consumption for industrial facilities processes is in the dop three for all manufacturing segments.

For the five segments with 14% savings in 2035, the top three processes are industrial facilities, fans and blowers and pumps. There is some uniformity in the savings across processes and NAICS due to the assumptions made in the top-down modeling of industrial. The assumptions for process-level savings by NAICS are presented in Appendix G.

Table 4-4
Top Three Manufacturing Processes for 2035 Achievable Potential, by NAICS Code

Division	Process	Savings (GWh)	% of Baseline
311&312 Food, Beverage & Tobacco	Industrial Facilities	2,203	2.2%
	Process Cooling and Refrigeration	2,056	2.1%
	Pumps	1,028	1.0%
313-316 Clothing	Industrial Facilities	2,104	9.7%
	Fans and Blowers	437	2.0%
	Pumps	435	2.0%
321&322 Wood Products Pulp & Paper	Pumps	2,814	3.0%
	Fans and Blowers	1,219	1.3%
	Industrial Facilities	985	1.0%
323 Printing	Industrial Facilities	1,491	9.7%
	Fans and Blowers	310	2.0%
	Pumps	308	2.0%
324 Petroleum and Coal Products	Pumps	1,037	1.8%
	Industrial Facilities	691	1.2%
	Compressed Air	374	0.6%
325 Chemicals & Allied Products	Pumps	2,807	1.8%
	Industrial Facilities	1,871	1.2%
	Compressed Air	1,014	0.6%
326 Plastics	Industrial Facilities	1,936	3.5%
	Process Heating	640	1.2%
	Fans and Blowers	554	1.0%
327 Non-Metallic	Industrial Facilities	1,357	3.5%
	Process Heating	897	2.3%
	Fans and Blowers	388	1.0%
331 Primary Metals	Industrial Facilities	3,229	2.4%
	Pumps	2,018	1.5%
	Process Heating	1,480	1.1%
332 Fabricated Metals	Industrial Facilities	917	2.2%
	Pumps	253	0.6%
	Process Heating	190	0.5%

Table 4-4 (continued)
Top Three Manufacturing Processes for 2035 Achievable Potential, by NAICS Code

Division	Process	Savings (GWh)	% of Baseline
333 Machinery	Industrial Facilities	487	2.2%
	Pumps	134	0.6%
	Process Heating	67	0.3%
334 Computer Equipment	Industrial Facilities	3,588	9.7%
	Fans and Blowers	745	2.0%
	Pumps	742	2.0%
335 Appliance Manufacturing	Industrial Facilities	1,187	9.7%
	Fans and Blowers	246	2.0%
	Pumps	245	2.0%
336 Transportation Equipment	Industrial Facilities	966	2.2%
	Pumps	267	0.6%
	Process Heating	133	0.3%
337 Furniture	Industrial Facilities	124	2.2%
	Pumps	34	0.6%
	Process Heating	17	0.3%
339 Miscellaneous Manufacturing	Industrial Facilities	893	9.7%
	Fans and Blowers	186	2.0%
	Pumps	185	2.0%

Regional Analysis

While many of the trends in the baseline energy use and potential savings are evident at the national level, it is also useful to analyze the regional results. This provides a better understanding of the various components of the aggregate United States results reported in this section, in addition to providing greater insight to a reader interested in a specific geographic area. To aid this investigation, complete analyses for each of the four census divisions are included in Appendices A through D. The present section discusses the regional results comparatively and at a high level, rather than repeating the analysis by sector, end use and measure.

Figure 4-44 illustrates how the 2035 achievable potential is split across the divisions. Not surprisingly the divisions within the South Census region (shown in shades of orange) together comprise the greatest share of 2035 achievable potential. This is driven by the fact that the South Census region also comprises the greatest share of the baseline forecast. However as is shown in Appendix B this is also due to the end uses present in the South and increased opportunities in electric space heating and cooling.

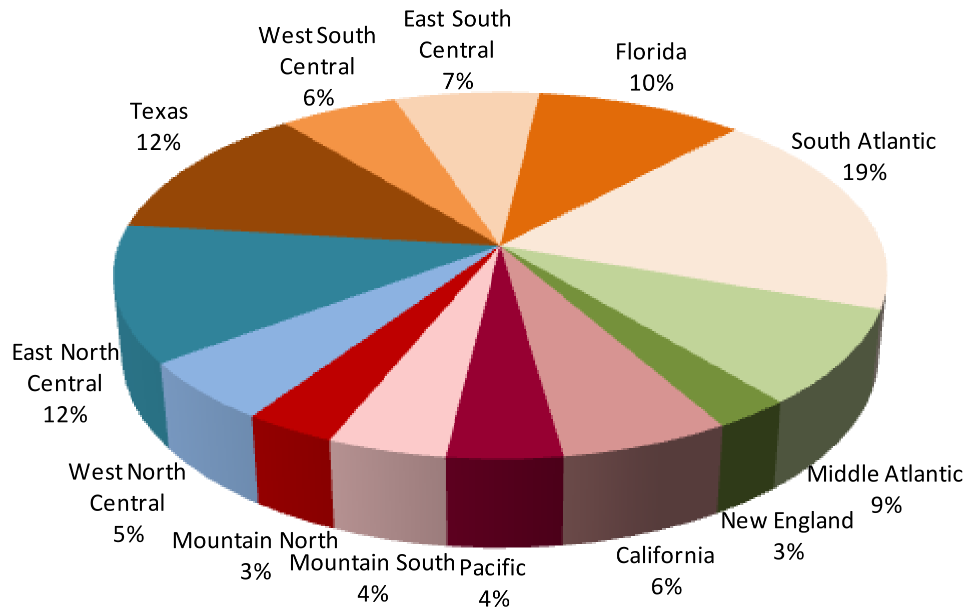

Figure 4-44
Division Shares of 2035 Achievable Potential

Table 4-5 shows the absolute values for 2035 achievable potential by division and this is broken out by sector. In all cases the potential for savings is greatest in the commercial sector with indoor lighting providing top savings across the board.

Table 4-5
2035 Achievable Potential by Division and Sector

	Residential	Commercial	Industrial	Total
Northeast Census Region				
New England	2,795	9,359	1,321	13,475
Middle Atlantic	7,383	30,620	3,090	41,093
South Census Region				
South Atlantic	29,666	54,312	5,912	89,889
Florida	19,432	27,089	2,946	49,468
East South Central	11,749	15,282	7,639	34,670
West South Central	9,326	15,424	3,442	28,192
Texas	22,840	29,857	6,663	59,360
Midwest Census Region				
East North Central	8,625	40,488	9,602	58,715
West North Central	7,204	14,611	4,232	26,047
West Census Region				
Mountain North	3,664	10,258	2,235	16,158
Mountain South	6,016	12,180	2,654	20,850
Pacific	3,772	14,024	2,399	20,195
California	6,035	20,315	3,475	29,826

Figure 4-45 illustrates how the savings in each sector compares to the division's baseline consumption. Although the absolute savings vary among divisions, the savings as a percentage of the division's baseline range from 8% to 14%. In all but one Southern division the savings are the highest across all divisions, while in the Midwest divisions (East North Central and West North Central) the savings are below 10% of the baseline.

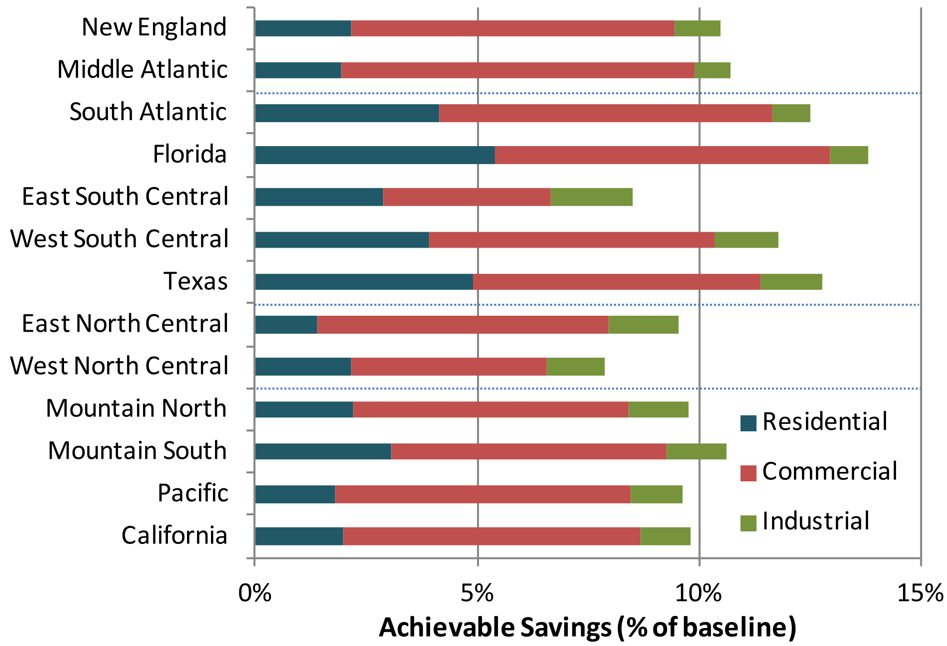

Figure 4-45
2035 Division-Level Achievable Potential as a Percentage of Division Baseline

Table 4-6 through Table 4-9 lend some insight into the differences between savings among the divisions. Commercial indoor lighting is top in all divisions, the other top saving end uses lend some insight into variations in end-use consumption amongst the divisions.

Table 4-6 shows the top three end uses for 2035 achievable potential for the Northeast divisions. Electronics, either miscellaneous electronics for commercial or residential computers present relatively high opportunities for savings compared to other end uses. It would be useful to better understand trends in electronics in the Northeast in the future to best understand how the potential for savings will change over time.

Table 4-6
Top Three End Uses for 2035 Achievable Potential, Northeast Census Region

Division	End Use	Savings (GWh)	% of Baseline
New England	Commercial Indoor Lighting	6,680	5.2%
	Residential Computers	882	0.7%
	Commercial Other Electronics	742	0.6%
Middle Atlantic	Commercial Indoor Lighting	20,842	5.4%
	Commercial Other Electronics	2,729	0.7%
	Residential Computers	2,436	0.6%

Notes: New England includes NH, VT, ME, MA, RI, and CT. Middle Atlantic includes NY, NJ, and PA.

The top three end uses in the South are shown in Table 4-7. Central air conditioning both in the residential and commercial sectors make it into the top three in almost all cases. This fact points to the increased consumption for space cooling in the South. The end-use category, "industrial facilities", also makes it into the top three in the East South Central and presents the largest opportunity for savings in the industrial sector.

Table 4-7
Top Three End Uses for 2035 Achievable Potential, South Census Region

Division	End Use	Savings (GWh)	% of Baseline
South Atlantic	Commercial Indoor Lighting	31,595	4.4%
	Residential Central AC	9,198	1.3%
	Commercial Central AC	7,154	1.0%
Florida	Commercial Indoor Lighting	15,746	4.4%
	Residential Central AC	6,735	1.9%
	Commercial Central AC	3,567	1.0%
East South Central	Commercial Indoor Lighting	10,367	2.5%
	Industrial Facilities	3,233	0.8%
	Residential Central AC	3,211	0.8%
West South Central	Commercial Indoor Lighting	8,228	3.4%
	Residential Central AC	3,310	1.4%
	Commercial Central AC	3,036	1.3%
Texas	Commercial Indoor Lighting	15,929	3.4%
	Residential Central AC	11,253	2.4%
	Commercial Central AC	5,873	1.3%

Notes: South Atlantic includes WV, VA, DE, MD, DC, NC, SC, and GA. East South Central includes KY, TN, MS, and AL. West South Central includes OK, AR, and LA.

Table 4-8 presents the top three for the Midwest. Industrial facilities is in the top three for both divisions, which includes industrial HVAC and lighting. Otherwise no heating or cooling makes it into the top three in the Midwest where there is less electric space heating and cooling than in other divisions.

Table 4-8
Top Three End Uses for 2035 Achievable Potential, Midwest Census Region

Division	End Use	Savings (GWh)	% of Baseline
East North Central	Commercial Indoor Lighting	28,222	4.6%
	Industrial Facilities	4,043	0.7%
	Commercial Other Electronics	3,681	0.6%
West North Central	Commercial Indoor Lighting	10,367	3.1%
	Industrial Facilities	1,782	0.5%
	Residential Computers	1,544	0.5%

Notes: East North Central includes WI, MI, IL, IN, and OH. West North Central includes ND, SD, MN, NE, IA, KS, and MO.

Table 4-9 shows mixed results for the West with electronics – residential computer or commercial electronics – showing up in a few of the West divisions. Mountain South has residential cooling in the top three pointing to the relatively high share of central AC consumption in the baseline.

Table 4-9
Top Three End Uses for 2035 Achievable Potential, West Census Region

Division	End Use	Savings (GWh)	% of Baseline
Mountain North	Commercial Indoor Lighting	6,668	4.0%
	Industrial Facilities	1,011	0.6%
	Residential Computers	902	0.5%
Mountain South	Commercial Indoor Lighting	7,917	4.0%
	Residential Central AC	1,810	0.9%
	Industrial Facilities	1,201	0.6%
Pacific	Commercial Indoor Lighting	9,089	4.3%
	Commercial Other Electronics	1,744	0.8%
	Residential Computers	1,340	0.6%
California	Commercial Indoor Lighting	13,167	4.3%
	Commercial Other Electronics	2,526	0.8%
	Residential Computers	1,941	0.6%

Notes: ASHP = air-source heat pumps. Mountain North includes MT, ID, WY, UT, and CO. Mountain South includes AZ, NM, and NV. Pacific includes WA, OR, AK, and HI.

Section 5: Peak Demand Reduction Potential

In addition to delivering energy savings, energy efficiency can also reduce peak demand as a function of the reduction in usage that is coincident to the system peak. In the residential and commercial sectors winter and summer coincident peak demand is defined at the end-use level using load and coincidence factors along with the annual energy consumption. This allows summer and winter demand forecasts to be built bottom up as presented in Section 3. A similar approach is taken in the industrial sector where coincidence and load factors are applied, but from the top down to get demand forecasts at the process level, and are also presented in Section 3.

All efficiency measures also have associated demand savings in the EPRI model – some may be 0% where they afford no demand savings. As the passing efficient measures roll into the stock turnover producing energy savings, the demand savings are also tabulated. The resulting summer and winter coincident peak demand forecasts with the impacts of efficiency incorporated are shown in Figure 5-1 and Figure 5-2 respectively.

The achievable potential for summer demand savings reduces the annual growth rate for 2012 to 2035 from the baseline 0.8% to 0.28%. The achievable potential for winter demand savings reduces the annual growth rate for 2012 to 2035 from 1.03% to 0.56%.

The wide margin between the technical and economic potentials in the summer demand forecasts illustrates the difference between the potential if the most efficient technologies are adopted versus the most efficient *cost-effective* technologies. The disparity is more pronounced than in the case of winter demand. The technical potential savings for 2035 summer coincident demand is almost 40% compared to almost 30% for winter coincident demand technical potential. In both cases the economic potential is about 20% of the baseline, therefore there must be greater summer demand savings available through the most efficient technologies adopted in the technical potential.

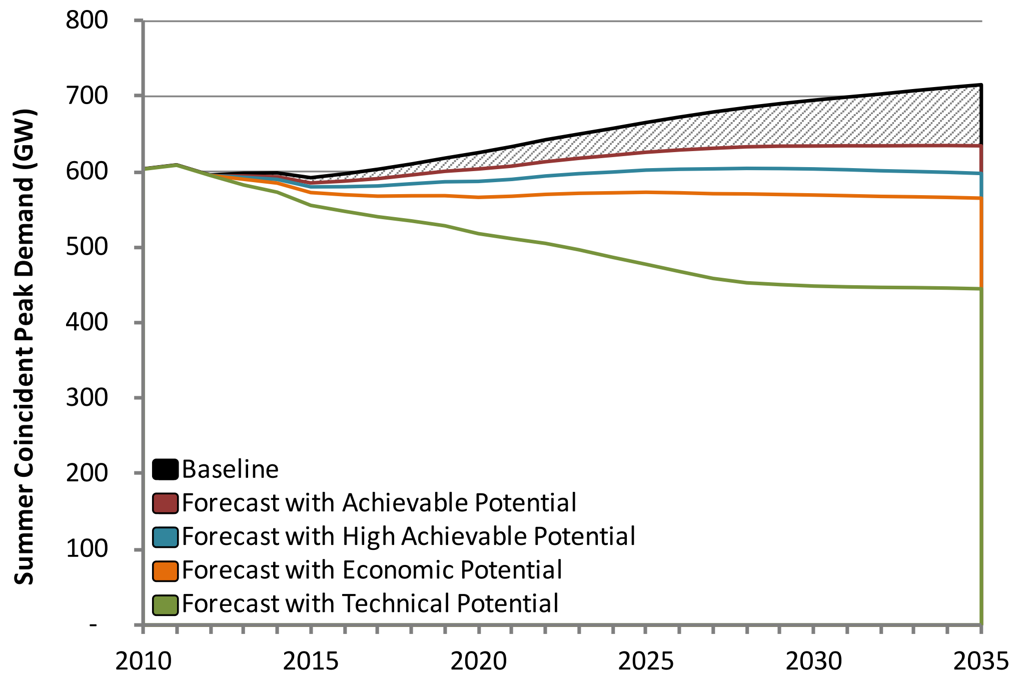

Figure 5-1
U.S. Energy Efficiency Summer Coincident Peak Demand Potentials in Context of the Baseline Forecast

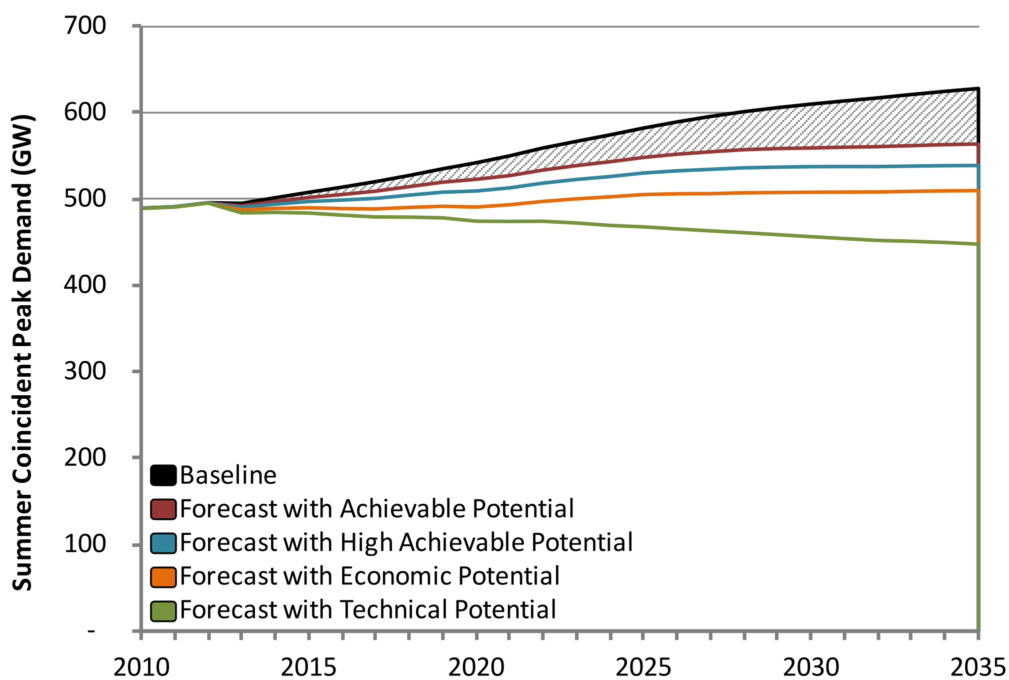

Figure 5-2
U.S. Energy Efficiency Winter Coincident Peak Demand Potentials in Context of the Baseline Forecast

Summer Peak Demand Savings

Figure 5-3 shows the various levels of potential for summer coincident demand savings in the key forecast years, with 11.1% achievable potential in 2035 across all sectors. This illustrates how the potential builds over time as the efficient measures are installed.

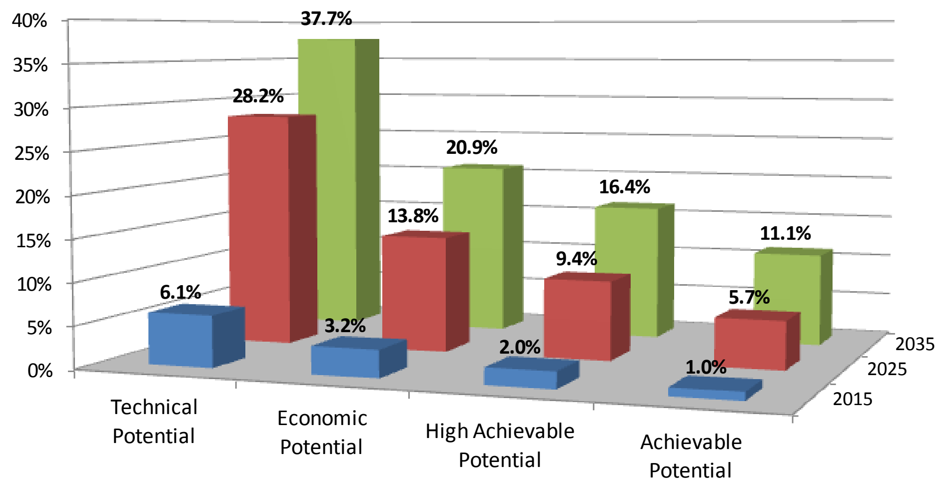

Figure 5-3
U.S. Summer Coincident Peak Demand Reduction

Figure 5-4 breaks out the achievable potential by sector as a percentage of each sector's baseline. Clearly there is great potential for savings in the commercial sector, which is in line with the energy savings results presented in Section 4.

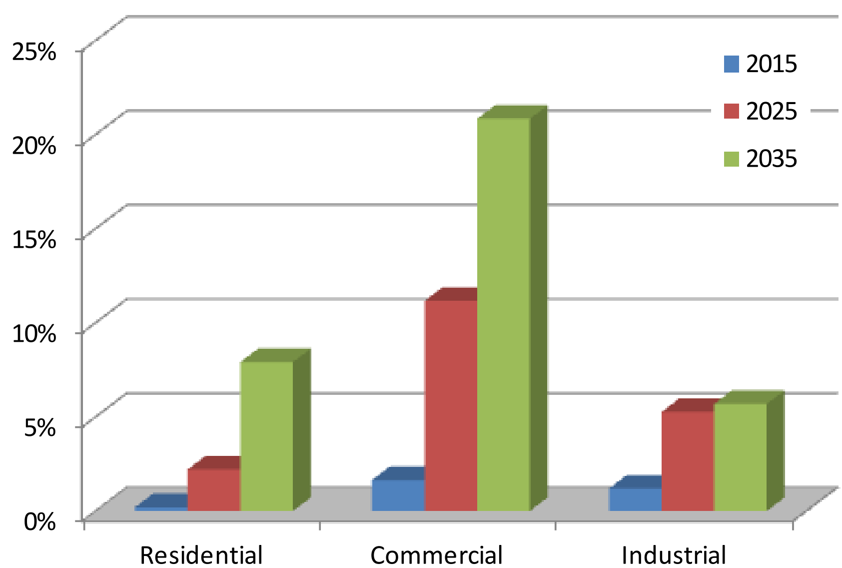

Figure 5-4
Summer Peak Demand Achievable Potential by Sector, as Percentage of Sector Energy Baseline

Table 5-1 presents summer coincident peak demand achievable savings potential by sector and end use, the achievable potential savings in 2035 across all sectors is 11.1%. The majority of summer demand savings are in the areas of HVAC, water heating and lighting, together accounting for 69% of the 2035 savings.

Space cooling in the residential and commercial sectors accounts for about 30% of summer demand savings in 2035. Lighting accounts for another 30% of 2035 achievable potential. These do not include industrial facilities, which captures HVAC and lighting savings in the industrial sector.

Table 5-1
Achievable Summer Peak Demand Reductions by Sector and End Use (MW)

	2015	2025	2035
Residential			
Space Cooling	377	4,034	16,787
Electronics	145	1,532	5,689
Water Heating	73	959	2,996
Lighting	92	1,233	2,705
Appliances	48	490	1,373
Residential Total	**735**	**8,248**	**29,550**
Commercial			
Lighting	2,886	15,545	22,236
Office Equipment	304	4,391	12,867
Space Cooling	126	2,404	6,513
Ventilation	9	172	428
Water Heating	1	1	1
Refrigeration	0.0	0.0	1
Commercial Total	**3,326**	**22,512**	**42,046**
Industrial			
Industrial Facilities	718	3,172	3,429
Pumps	372	1,646	1,784
Fans and Blowers	194	861	933
Process Cooling & Refrigeration	140	616	665
Process Heating	132	584	630
Compressed Air	90	398	432
Steam Generation Equipment	13	57	62
Industrial Total	**1,660**	**7,334**	**7,935**
U.S. Total	**5,721**	**38,094**	**79,531**

Note: Numbers in table may not sum to the total due to rounding.

Figure 5-5 illustrates the summer demand achievable savings by sector and end use, with the end uses ordered by their 2035 savings. Space cooling is in the top three end uses in each sector and commercial lighting is the top saving end use across all sectors.

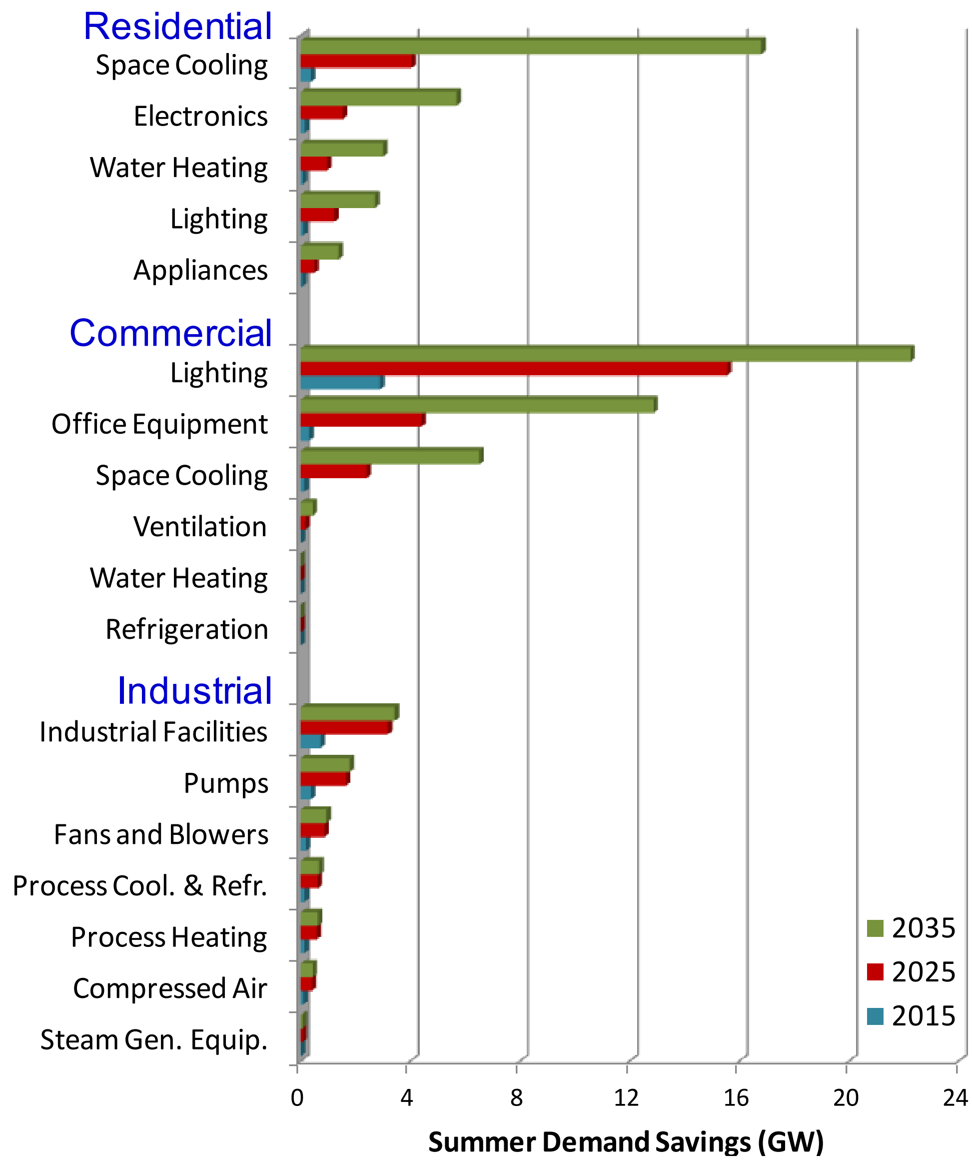

Figure 5-5
Achievable Summer Peak Demand Reductions by Sector and End Use

Winter Peak Demand Savings

Figure 5-6 shows the various levels of potential for winter coincident demand savings in the key forecast years, with 10.2% achievable potential in 2035 across all sectors. This illustrates how the potential builds over time as the efficient measures are installed.

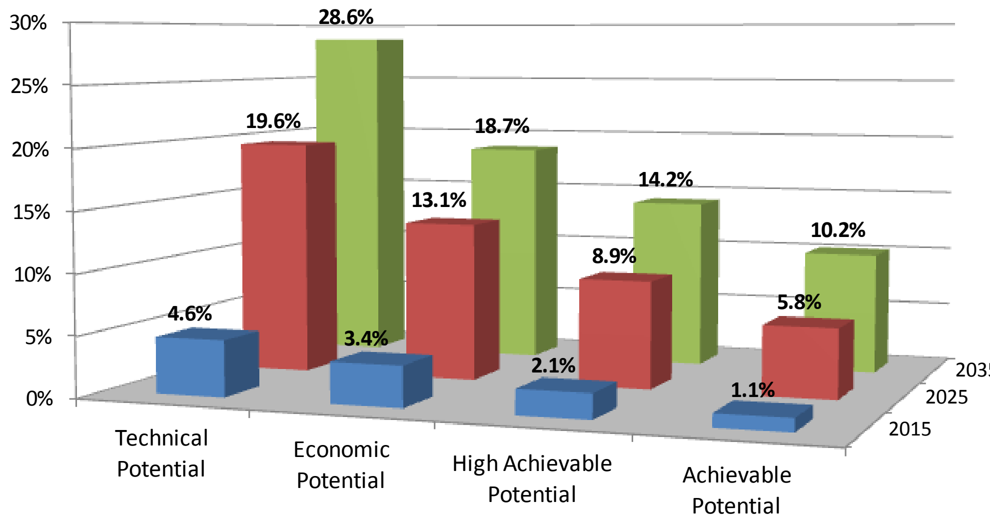

Figure 5-6
U.S. Summer Coincident Peak Demand Reduction

Figure 5-7 breaks out the achievable potential by sector as a percentage of each sector's baseline. The relatively high potential in the commercial sector, is again evident.

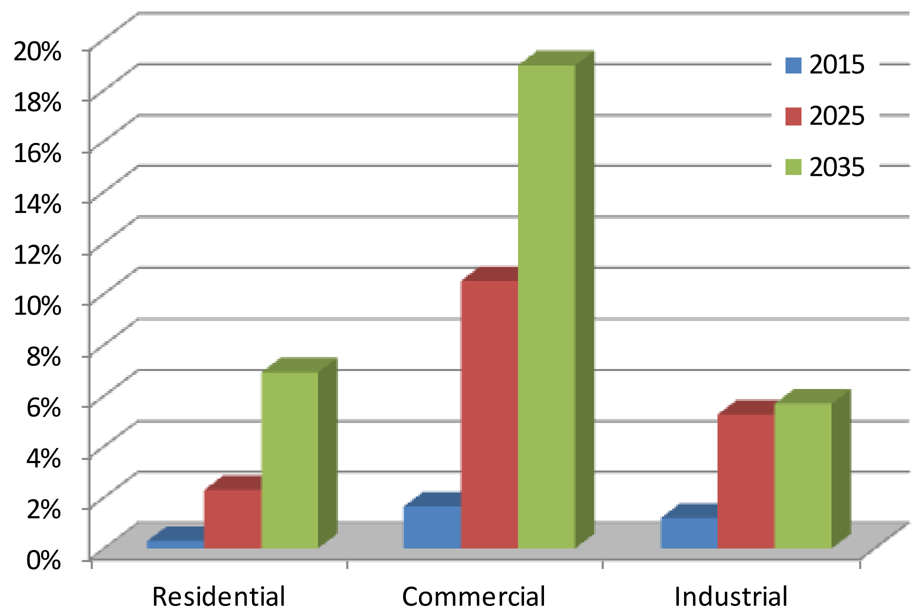

Figure 5-7
Winter Peak Demand Achievable Potential by Sector, as Percentage of Sector Energy Baseline

Table 5-2 presents winter coincident peak demand achievable savings potential by sector and end use, the achievable potential savings in 2035 across all sectors is 10.2%. The majority of winter demand savings are also in the areas of HVAC, water heating and lighting, together accounting for 62% of the 2035 savings.

Energy efficiency in heating end uses does not have quite as much impact on winter demand savings as space cooling on summer demand, accounting for about 14% of 2035 achievable potential. Lighting presents the bulk of savings potential for winter demand contributing about 40% of the total. Again, space heating and lighting savings from industrial facilities is not included in these totals due to lack of details on how it is broken out.

Table 5-2
Achievable Winter Peak Demand Reductions by Sector and End Use (MW)

	2015	2025	2035
Residential			
Space Heating	236	2,288	8,361
Electronics	123	1,306	4,848
Lighting	413	2,236	4,479
Water Heating	55	721	2,233
Appliances	44	453	1,252
Residential Total	**871**	**7,004**	**21,173**
Commercial			
Lighting	2,659	14,410	20,788
Office Equipment	305	4,403	12,903
Space Heating	11	157	465
Ventilation	10	176	439
Water Heating	2	3	2
Refrigeration	0.0	0.0	0.5
Commercial Total	**2,986**	**19,149**	**34,598**
Industrial			
Industrial Facilities	718	3,172	3,429
Pumps	372	1,646	1,784
Fans and Blowers	194	861	933
Process Cooling and Refrigeration	140	616	665
Process Heating	132	584	630
Compressed Air	90	398	432
Steam Generation Equipment	13	57	62
Industrial Total	**1,660**	**7,334**	**7,935**
U.S. Total	**5,517**	**33,487**	**63,706**

Note: Numbers in table may not sum to the total due to rounding.

Figure 5-8 illustrates the winter demand achievable savings by sector and end use, with the end uses ordered by their 2035 savings. Space heating is in the top three end uses in each sector and again commercial lighting is the top saving end use across all sectors.

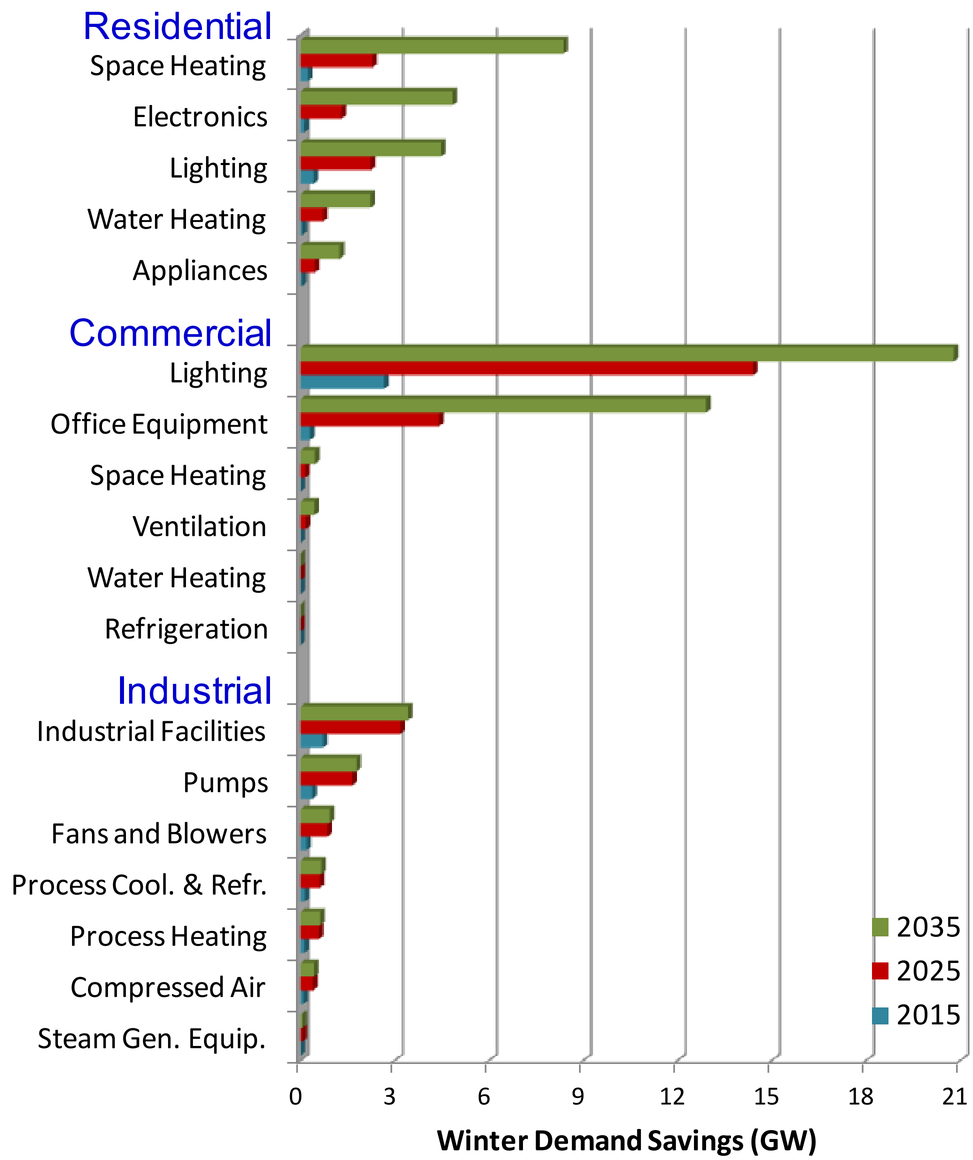

Figure 5-8
Achievable Winter Peak Demand Reductions by Sector and End Use

Section 6: The Cost of Achievable Potential

This study has employed a net present value approach to determine whether a measure is economic for the participant and from the perspectives of other affected groups. These may include the non-participants, the utility, both from an obligation to serve standpoint and from a cash flow basis, as well as society. Each of these perspectives has its perspective in evaluating the appropriateness of investments in conventional generating resources and energy efficiency and demand-side resources.

Electricity is a capital intensive activity that produces two outputs – power and energy. Both have value to the utility in meeting demands placed on the system by its customers. Different resources have the ability to meet each of those supply dimensions in different ways. For example base load generating units such as nuclear or coal plants produce power e evenly through the year. Peaking units such as combined cycle units produce power over different levels of output. Baseload units have high upfront cost but low variable costs and long lives. Combined cycle units have much lower upfront costs much higher variable costs but shorter lives.

Levelized cost of energy (LCOE) is a means to compare the costs of different units, each with different operating characteristics, on a similar basis. It provides a common framework for comparing generation of varying operating characteristics with generating resources. It can also be used to make a comparison between generation resources and energy efficiency and demand response assets as well.

LCOE captures all of the costs to install and operate a resource, demand side or supply side, and captures the effects of the time value of money and inflation in the cost streams. It then takes those present worth costs and divides by the amount of energy or demand the units provide.

The main shortcoming of LCOE is that is fails to capture the system need for the combined demand and energy components. An electric system that needs capacity may choose an energy resource when in fact a demand resource is more appropriate. Electric resource planners use other methods that better capture those effects.

LCOE also fails to value dispatchable versus non-dispatchable loads – the difference between wind resources and combustion turbines for instance. LCOE also does not capture cash flows.

LCOE however, does have the advantage of providing a simple and easy to understand method to compare similar resource characteristics with varying lives. LCOE allows the construction of a supply curve which can illustrate the costs of alternative resources – demand and supply side, in a form similar to a supply curve of resources. For that reason it is often shown in the form of a supply curve that can be used to compare baseload supply side resources with energy efficiency.

Figure 6-1, Figure 6-2, and Figure 6-3 present the LCOE for achievable potential by end use in each sector. The width of each end use's slice represents the annual achievable potential for that end use.

Residential levelized costs vary from less than 0.01 $/kWh for dishwashers up to almost 0.07 $/kWh for linear fluorescent lighting. Both central AC and screw-in lighting show high potential for annual achievable potential. Referring back to the top end uses for residential achievable potential the central AC results are expected. However, due to EISA 2007 by 2035 lighting falls down the list of top savings end uses. Early on before the full impacts of Tier 2 EISA 2007, lighting presents the greatest opportunity for savings in the residential sector. The winning technologies in all divisions early in the forecast are LED lamps with a lifetime of over 20 years, which provides years of savings once installed and therefore the savings early on provide carry over savings throughout the forecast. As lighting stock turns over the MARs and PIFs limits the installation of LED in the achievable potential compared to the economic potential.

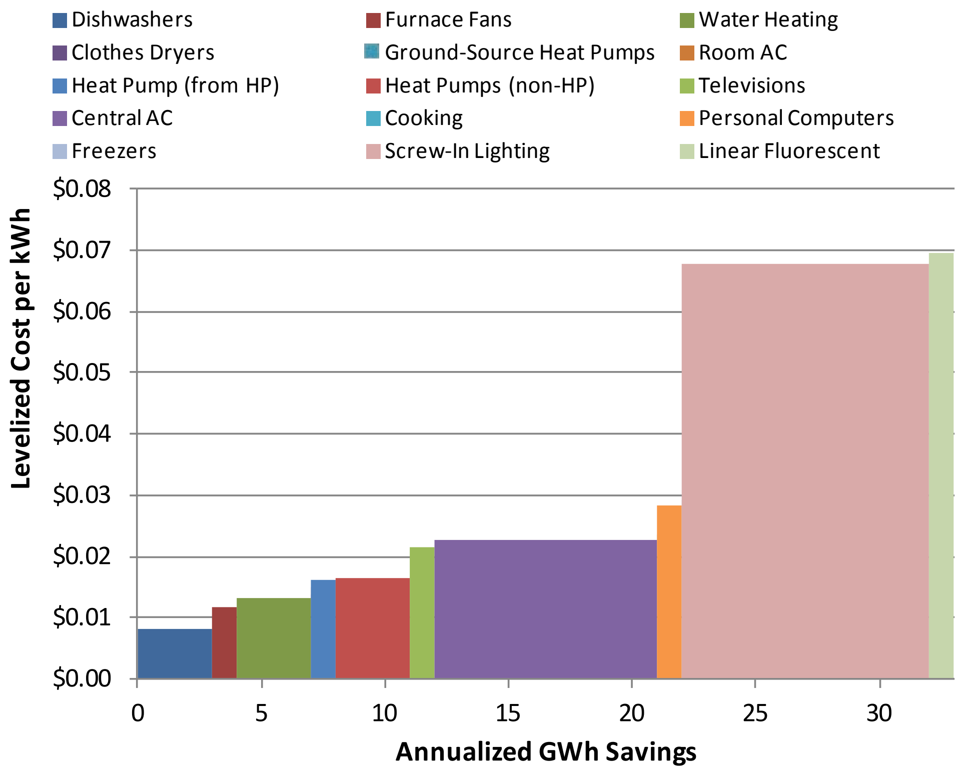

Figure 6-1
Residential Energy Efficiency Supply Curve

Commercial levelized costs shown in Figure 6-2. Commercial levelized costs vary from almost -0.01 $/kWh for HID lighting up to a little over 0.07 $/kWh for linear fluorescent lighting. The incremental costs for HID lighting are actuall negative, so the more efficient technology costs less than the base option, therefore the levelized costs are less than zero. Similar to the residential results lighting presents large opportunities for annual achievable potential. The large savings in screw-in lighting compared to the 2035 achievable potential ahs the same reasoning as in the residential sector.

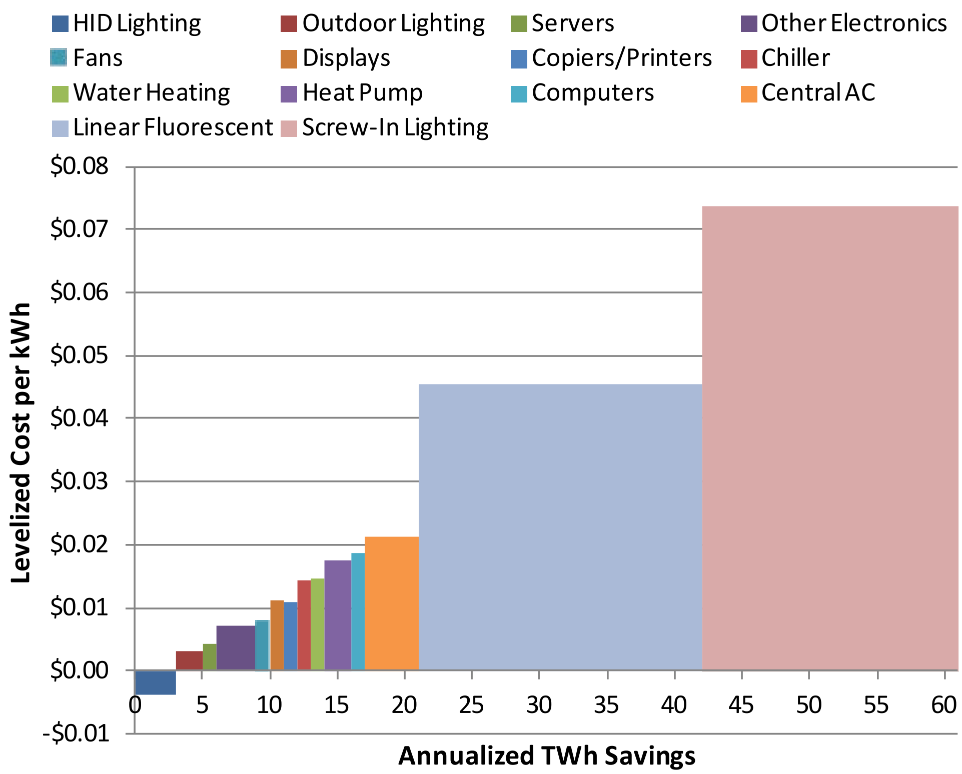

Figure 6-2
Commercial Energy Efficiency Supply Curve

Industrial levelized costs are shown in Figure 6-3. Industrial levelized costs vary from just under 0.01 $/kWh for several processes up to about 0.04 $/kWh for industrial facilities.

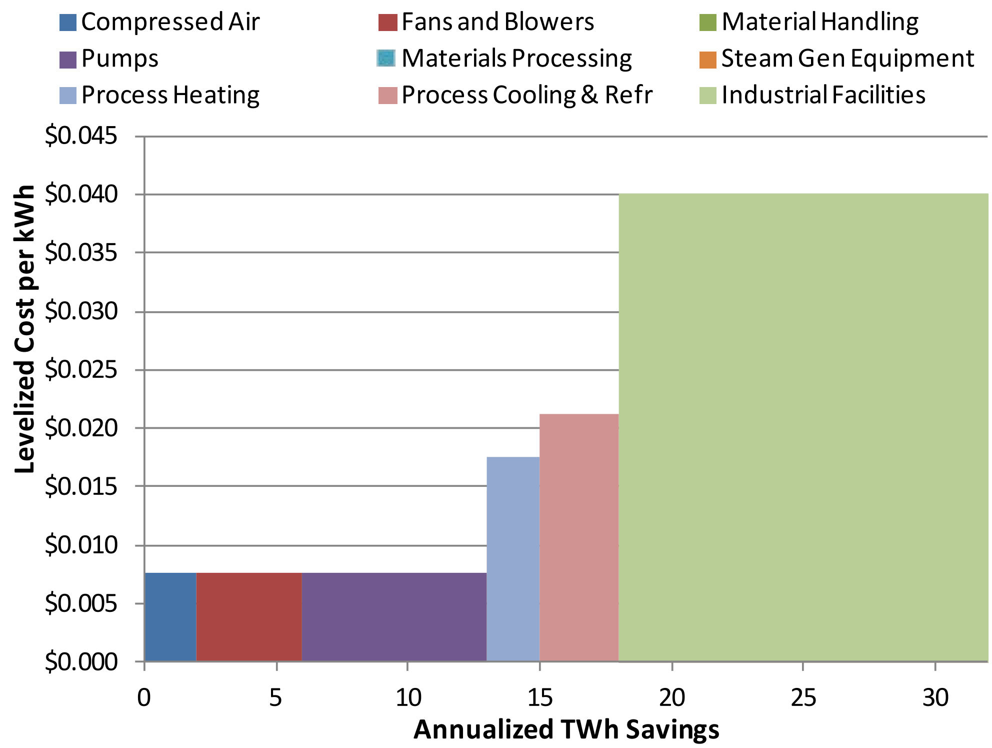

Figure 6-3
Industrial Energy Efficiency Supply Curve

Total Projected Costs

Table 6-1 shows cumulative incremental costs for installing efficient technologies along with the assumed program administration costs. There were no incentives assumed in this analysis. However incentives provided by utilities offer cover a portion of the incremental costs of technologies. In this case, because the TRC was used to determine cost-effectiveness and incentives do not come into play, the inclusion of incentives would not have changed the achievable potential.

For this study the program administration costs were assumed to be 20% of the incremental costs of the technologies. To capture the achievable potential assessed in the study over the forecast period would cost $401 Billion in capital costs and $80 Billion in program administration costs for utility-administered programs.

Table 6-1
Cumulative Incremental and Program Administration Costs for Achievable Potential (Millions of Dollars)

	2015	2025	2035
Incremental costs			
Residential	$19,784	$49,863	$150,341
Commercial	$17,776	$100,090	$249,671
Industrial	$233	$1,028	$1,180
Total	**$37,793**	**$150,981**	**$401,192**
Program administration costs			
Residential	$3,957	$9,973	$30,068
Commercial	$3,555	$20,018	$49,934
Industrial	$47	$206	$236
Total	**$7,559**	**$30,197**	**$80,238**

Section 7: Load Growth from Electric Transportation

Adoption of new electric end uses such as plug-in electric vehicles (PEV) will lead to increased electricity consumption that will counter the impacts of energy efficiency and conservation to some extent. This will include both on- and non-road vehicles where fossil-fueled options were previously used. PEVs include both battery electric vehicles (BEV) that use only electricity, and plug-in hybrid electric vehicles (PHEV) that use both electricity and gasoline but can travel some distance using only electricity. Both BEVs and PHEVs are often categorized by their electric range, or the number of miles they can travel using only electricity under a standard set of driving conditions.

The consumption forecast for electricity consumed by light-duty vehicles and non-road vehicles is shown in Figure 7-1. Overall expected electricity consumption for light-duty and non-road PEVs combined could be as high as 177 TWh per year, in the high scenario.

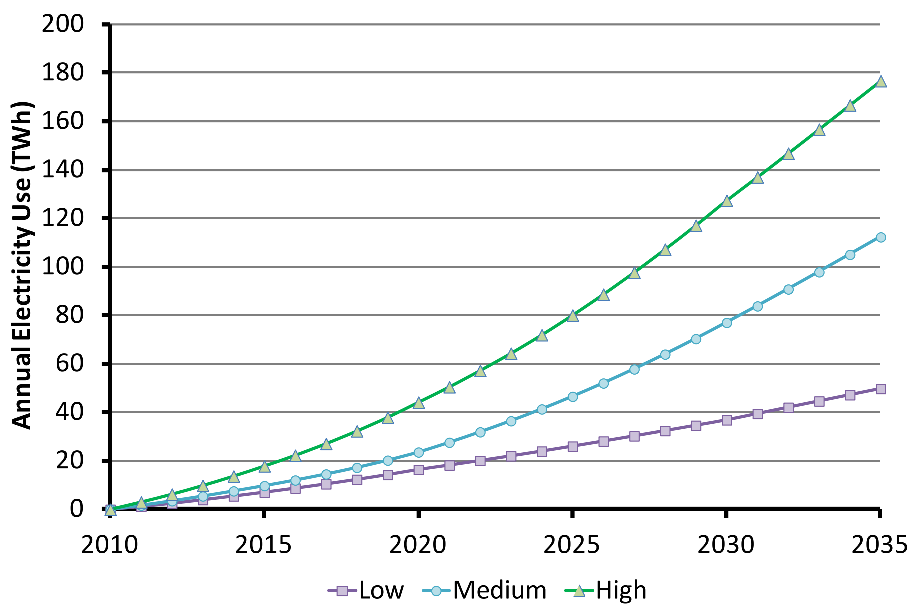

Figure 7-1
U.S. Transportation Electricity Consumption Forecast, On-Road and Off-Road

Note: This includes only the lower 48 states, Hawaii and Alaska are not included.

As described in the following sections the forecast for light-duty vehicles is the overall potential for electricity consumption, not the potential increase in consumption. Since the AEO baseline used throughout the rest of the study does not include electricity consumed for transportation we can take the light-duty estimate as an additional component of total U.S. electricity consumption.

Fuel consumed for non-road transportation aside from rail is not included in the AEO transportation sector forecast, instead this fuel use is included in the primary sector where the equipment is used. The non-road portion of EPRI's estimate is assumed to be an increase from baseline consumption, however since the AEO (used throughout this study as the baseline) does not provide a separate estimate for most non-road electricity consumption, the non-road forecast presented herein is also taken to be an increase relative to electricity already accounted for in the residential, commercial and industrial baselines.[27]

For the reasons discussed in the preceding paragraphs we consider the transportation electrification estimates provided herein to be potential increase in electricity demand relative to the AEO2012 baseline that we are using for the residential, commercial and industrial sectors.

The total electricity forecast presented in Figure 7-1 is assumed to be analogous to the achievable potential level for energy efficiency estimates. The results from the efficiency potential analysis, transportation electrification and electrification in the residential, commercial and industrial sectors are compared in Section. 9.

The following sections describe the technology landscape for light duty PEVs and non-road PEVs and present methodologies for assessing penetration of various vehicle technologies over time along with the resulting forecasts for electricity consumption.

On-Road Transportation

As of late 2012, the PEV market included 13 passenger vehicle models, with 5 more expected by the end of 2013. More than 150,000 PEVs have been sold since vehicles became available from major manufacturers, and cumulative sales are expected to surpass 500,000 vehicles by 2015.

However, the PEV market is still very much in its infancy. Some of the vehicle models are destined for limited production, two (Transit Connect Electric and Think City EV) have halted production, and some of the startup manufacturers are having difficulty with recalls or reliability. However, such fits and starts are to be expected with a burgeoning new industry, and overall PEV sales are showing consistent growth every month.

[27] An estimate of electricity for rail transportation is included in the AEO transportation sector forecast, however the estimate from AEO2012 was 7 TWh in 2012 and 9 TWh in 2035, this is a fraction of what the non-road portion of EPRI's estimate predicts (see Table 7-2), therefore there is little double counting in making these assumptions about electrification potential.

The *AEO2012* makes similar projections for vehicle penetration and electricity consumption forecasts. An overview of the light-duty vehicle estimates from the *AEO2012* is shown in Table 7-1.[28]

The compound annual growth rate for electricity consumption in light-duty vehicles is 19% from 2012 to 2035. The total electricity use in physical units is 7 TWh in 2012 and 22 TWh in 2035. Electricity consumption for rail transportation is also estimated in AEO, however modest growth is expected compared to light-duty vehicle electricity consumption. Even with moderate growth in electricity consumption, light-duty vehicle electricity is forecast to be a fraction of total light-duty energy consumption in 2035.

Table 7-1
AEO2012 Light-Duty Vehicle Sales and Energy Forecast

	2012	2015	2025	2035	CAGR (2012-2035)
New Vehicle Sales (thousands of vehicles)					
BEV, 100 Mile Range	2	6	103	340	24.9%
BEV, 200 Mile Range	0	0	0	0	-
PHEV, 10 Mile Range	0	41	100	140	-
PHEV, 40 Mile Range	12	34	73	74	8.4%
Other Light-Duty Sales	6,792	8,684	10,383	10,731	2.0%
Total Light-Duty Sales	**6,805**	**8,765**	**10,660**	**11,285**	**2.2%**
Total Vehicle Stock (thousands of vehicles)					
Total PEV	64	216	1,967	5,333	21.2%
Other Light-Duty	222,508	225,776	247,592	270,862	0.9%
Total Light Duty Stock	222,573	225,992	249,559	276,196	0.9%
Energy Consumption (trillion Btu)					
Light-Duty Electricity	1	2	15	45	19.0%
Other Light-Duty Energy	15,695	15,387	14,720	15,418	-0.1%
Total Light-Duty Energy	**15,696**	**15,389**	**14,735**	**15,463**	**-0.1%**

[28] Note that the AEO2012 does not include the greenhouse gas (GHG) and corporate average fuel economy (CAFE) standards for light-duty vehicles captured in the *AEO2013*. Therefore the forecast for energy consumption in the *AEO2013* is reduced as a result of increase in vehicle efficiency.

On-Road Estimation Approach and Forecasts

EPRI's PEV Load Estimator (PEVLE) tool is used to estimate market adoption forecasts of PEVs, including multiple market forces in the estimates. The tool forecasts new vehicle sales, cumulative PEV market penetration, resulting electricity consumption and greenhouse gas reductions.

The market penetrations are estimated without screening for cost-effectiveness, instead it is assumed that depending on the cost of the vehicle and fuel, local rebates and incentives and the individual's cost of capital that there will be some mix of technology adopted that may be cost-effective or not. Although the assumed uptake of PEVs is not necessarily a cost-effective increase in load it does lead to a net CO_2 reduction due to the fuel switching and is therefore beneficial from a societal perspective.

The *Adoption Forecasts* report[29] described a variety of market forces that affect the adoption of plug-in electric vehicles, including:

- **Refueling cost.** Gasoline and diesel prices are highly volatile, while electricity prices, particularly for residences, are in most cases very stable. By shifting some or all of the vehicle fuel to electricity, PEVs provide at least some help to increase certainty with fuel costs. Furthermore, in most situations, PEVs provide a significant reduction in vehicle refueling cost. With an all-electric vehicle, the cost may be reduced up to 75% or more.[30] The extent to which cost is reduced and stability is increased depends on the storage capacity of the PEV battery, other attributes of the vehicle design, the availability and usage of time-of-use electricity prices, and the user's driving patterns. PEVs may also provide a benefit of reduced maintenance costs.[31]
- **Initial vehicle price or lease costs.** The vehicle "sticker" price is one of the most influential components of a vehicle purchasing decision for vehicle buyers. The upfront price of PEVs is currently higher than a comparable traditional vehicle, but increasing competition in the PEV market will drive prices down. Leasing options may be attractive to some parties who wish to trade off vehicle ownership in favor of potentially lower monthly costs.
- **Incentives.** Governments, employers, and retailers offer various enticements to PEV owners including tax credits, discounts on PEV charging equipment, discounted or free charging, access to carpool lanes, and discounted parking.
- **Regulation.** There are federal rules covering fuel economy and greenhouse gases, minimum sales requirements for PEVs in California and some other states, and local regulations including building codes and permits that affect the cost of installing charging equipment. These rules impact the cost and availability of PEV s and associated charging facilities.

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[29] *Plug-In Electric Vehicle Adoption and Load Forecasting.* EPRI, Palo Alto, CA: 2012. 1024103.

[30] *Transportation Electrification: A Technology Overview.* EPRI, Palo Alto, CA: 2011. 1021334. Page 6-1.

[31] *Total Cost of Ownership for Current Plug-in Electric Vehicles.* EPRI, Palo Alto, CA: 2012. 1024848.

- **Environmental and political trends.** The relative level of concern over national security and the environment – and the public's opinion of how PEVs affect those concerns – affects interest in and acceptance of PEVs. These trends are sure to be different across various regions of the United States, Canada, and other countries.

Figure 7-2 and Figure 7-3 illustrate the result of EPRI's May 2013 forecast for light-duty PEV new-vehicle market share and cumulative fleet. Three cases are depicted (high, medium and low). EPRI's high case suggests that new vehicle market share could approach 35% by 2035 resulting in 6.4 million vehicles sold in 2035. The medium scenario is approximately 22% (and 4 million vehicles) and the low scenario approximately 7% (and between 1 and 2 million vehicles. These new-vehicle market shares result in a cumulative PEV fleet of between 14 and 60 million vehicles in 2035.

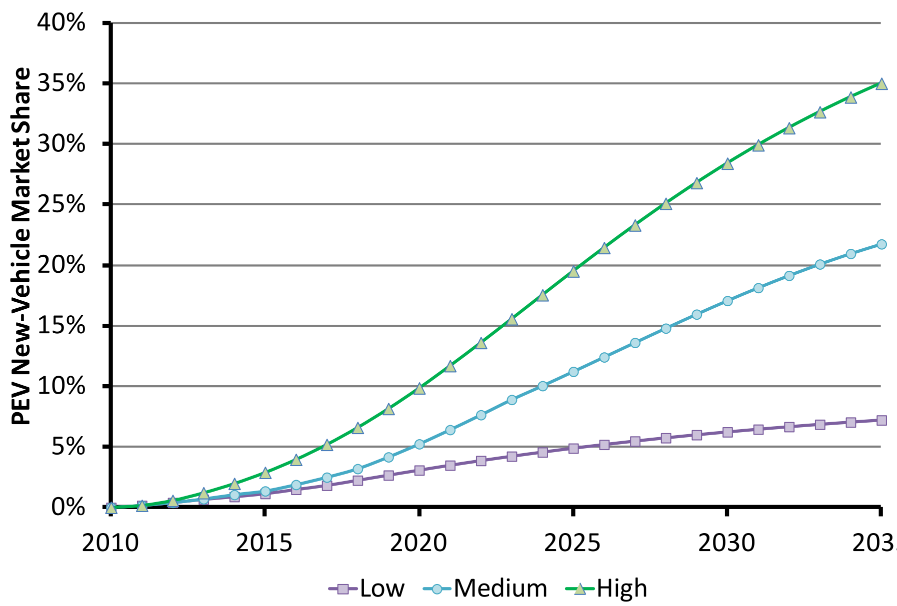

Figure 7-2
PEV New Vehicle Market Share through 2035

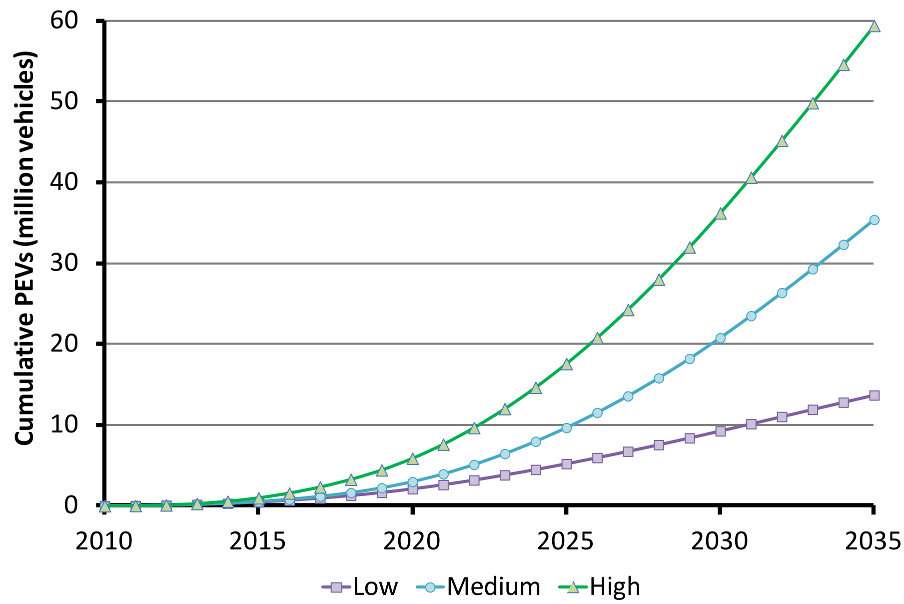

Figure 7-3
U.S. PEV Cumulative Vehicles through 2035

The AEO2012 projects that PEVs will account for less than 2% of new-vehicle sales in 2035 – about 550 thousand vehicles – with resulting electricity consumption of about 22 TWh in 2035, compared to EPRI's range of 7-35% of new-vehicle sales. Figure 7-4 illustrates the energy sales which would result from EPRI's penetration estimates with a range of between 26 TWh in the low scenario to 114 TWh in the high scenario.

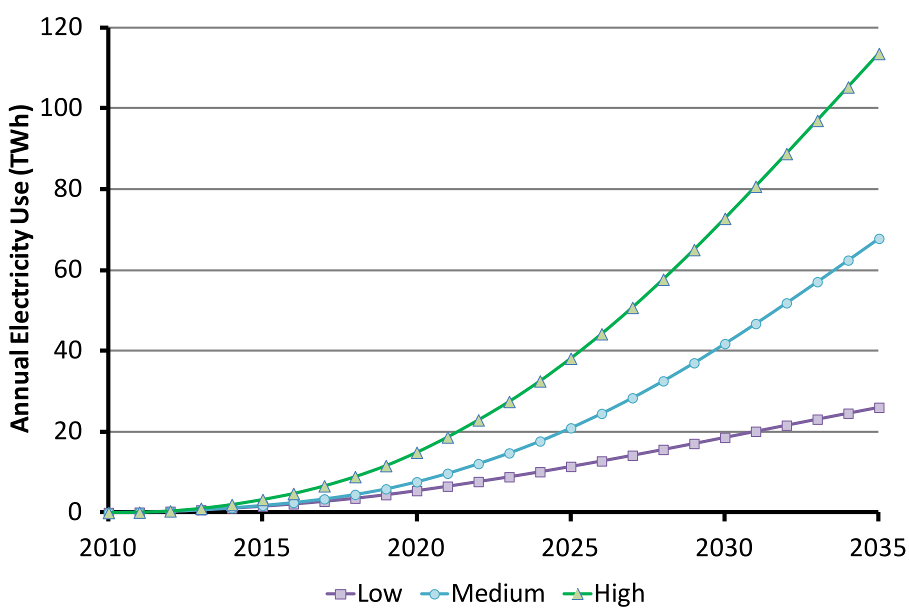

Figure 7-4
U.S. Electricity Consumption for On-Road PEV

Non-Road Transportation

Non-road transportation includes vehicles used for farming, construction and for purposes other than getting people or objects from one location to another. Fuel consumed for non-road transportation is not included in the AEO transportation sector forecast, instead this fuel use is included in the primary sector where the equipment is used. This makes it difficult to determine what the AEO forecasts for electricity consumed in non-road transportation. Presumably this is included in electricity consumed for "other uses" in the residential, commercial and industrial sectors.

Non-Road Estimation Approach and Forecasts

EPRI has done considerable work in estimating the potential for electrification of non-road vehicles, including both national studies and case studies for individual utilities. Most recently non-road electricity growth has been estimated in an EPRI air quality study to be released in 2014. The estimates represent additional electricity consumption from equipment electrified beyond what is expected in existing models. These estimates represent electrification potential in the lower 48 states, and do not include Alaska or Hawaii.

Three scenarios are included in the analysis:

- The low scenario assumes that the pace of replacement of fossil-fueled equipment with electric versions does not proceed as quickly as expected nor lead to as much electrification as expected.
- The medium scenario assumes that the pace of replacement of fossil-fueled equipment with electric versions proceeds as expected and represents a business-as-usual scenario.
- The high scenario assumes that the pace of replacement of fossil-fueled equipment with electric versions proceeds more quickly than expected and leads to more electrification than expected.

These market penetrations are again estimated without screening for cost-effectiveness, depending on the cost of the technology and fuel, and the individual's cost of capital that there will be some mix of technology adopted that may be cost-effective or not.

Estimated trends in increased non-road equipment electricity use presented in Figure 7-5 shows significant increases in electricity demand over the next 20 years. The electricity consumed in 2035 in the low scenario is similar to that for on-road, however the high scenario is about half of what's been forecast for the on-road high consumption.

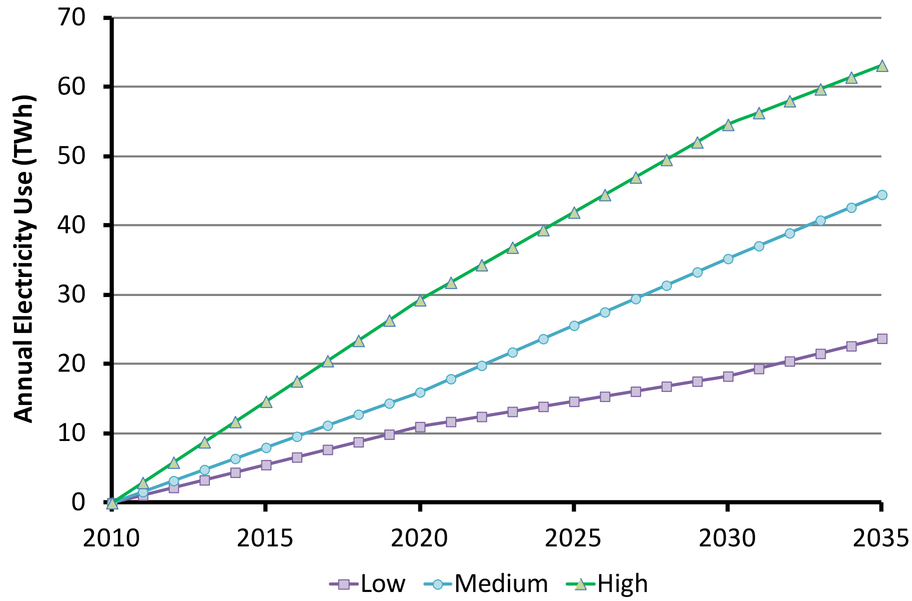

Figure 7-5
Increases in U.S. Electricity Demand from Non-Road Equipment to 2035

As shown in Table 7-2, in the mediums scenario, electricity use increases are expected to be greatest for rail transportation and industrial equipment. However, all equipment categories are forecast to have greater than 8% compound annual growth.

Table 7-2
Forecast of Non-Road Electricity Demand, Medium Scenario

	2012	2015	2025	2035	CAGR (2012-2035)
Agricultural Equipment	44	111	372	597	12.0%
Aircraft (APU)	17	42	94	116	8.8%
Airport Ground Support Equipment	41	104	377	680	12.9%
Harbor Craft	244	611	1,286	1,469	8.1%
Industrial Equipment	1,250	3,126	11,479	21,567	13.2%
Lawn and Garden Equipment	599	1,498	5,510	9,559	12.8%
OGV	760	1,901	4,760	7,350	10.4%
Rail	25	63	369	1,049	17.6%
Recreational Equipment	212	530	1,361	2,102	10.5%
TOTAL	**3,194**	**7,986**	**25,607**	**44,490**	12.1%

Note: For lower-48 states, does not include Hawaii or Alaska

Section 8: Load Growth from Electrification

In 2009, EPRI conducted a study to address the potential for expanding end-use applications of electricity.[32] The study focused on converting residential, commercial, and industrial equipment and processes – existing or anticipated – from traditional fossil-fueled end-use technologies to more efficient electric technologies. The study began with development of baseline forecasts of energy use and CO_2 emissions. The forecasts were consistent with the EIA's 2008 Annual Energy Outlook (*AEO2008*).[33] The study estimated the potential for primary energy savings and CO_2 emissions reductions during the years 2009 through 2030 for the residential, commercial, and industrial sectors as a function of end-use technology, fuel displaced, and census region. The analysis yielded forecasts of changes in primary energy use and energy-related CO_2 emissions for the U.S.

The basis for the study was evaluating the CO_2 emissions reduction potential of electric technologies, which in most cases reduces the primary energy consumed. However, the cost-effectiveness of these technologies was not assessed, therefore although all technologies applied save primary Btu, it is assumed that some of this would be cost-effective and some would not be cost-effective.

In a desire to align the forecast period with that used in this efficiency potential study, a cursory update was done in the residential portion using *AEO2012* data in place of the *AEO2008* data. The results were nearly identical in the first half of the forecast period with some difference in the out years. In addition, there has been little change in contributing factors over the last few years that would have significant impact on the predictions; therefore it is assumed that we can shift these forecasts for increased electricity demand to the 2013 to 2035 horizon to match the work presented in this study.

The primary results of the electrification study were forecasts for decrease in primary energy use and CO_2 emissions; in addition, the increase in electricity consumption has been extracted and is presented in Figure 8-1. The results of the electrification study included technical potential and realistic potential (achievable potential) forecasts for increase in electricity consumption.

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[32] *The Potential to Reduce CO2 Emissions by Expanding End-Use Applications of Electricity*, EPRI. Palo Alto, CA: 2009. 1018871.

[33] "Annual Energy Outlook 2008 with Projections to 2030," U.S. DOE EIA, Washington DC, DOE/EIA-0383(2008), June 2008. http://www.eia.gov/oiaf/aeo/pdf/0383(2008).pdf

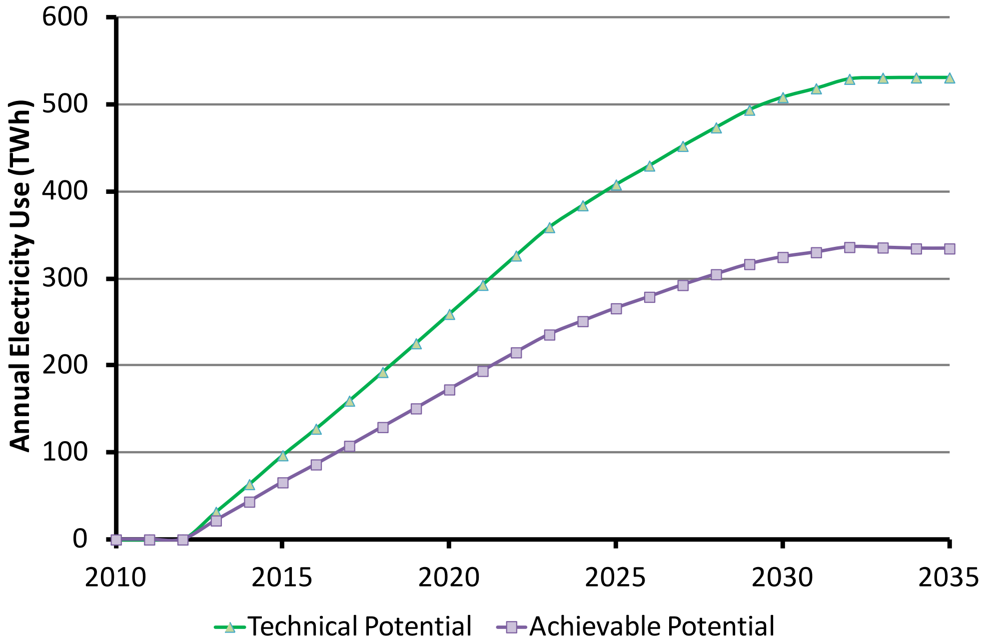


Figure 8-1
U.S. Electric Load Growth Forecast from Electrification

Figure 8-2 shows the achievable potential for load growth by sector for key forecast years. The residential presents the greatest potential for electrification with the goal of reducing CO_2 emissions. The commercial and industrial sectors show similar potential for growth.

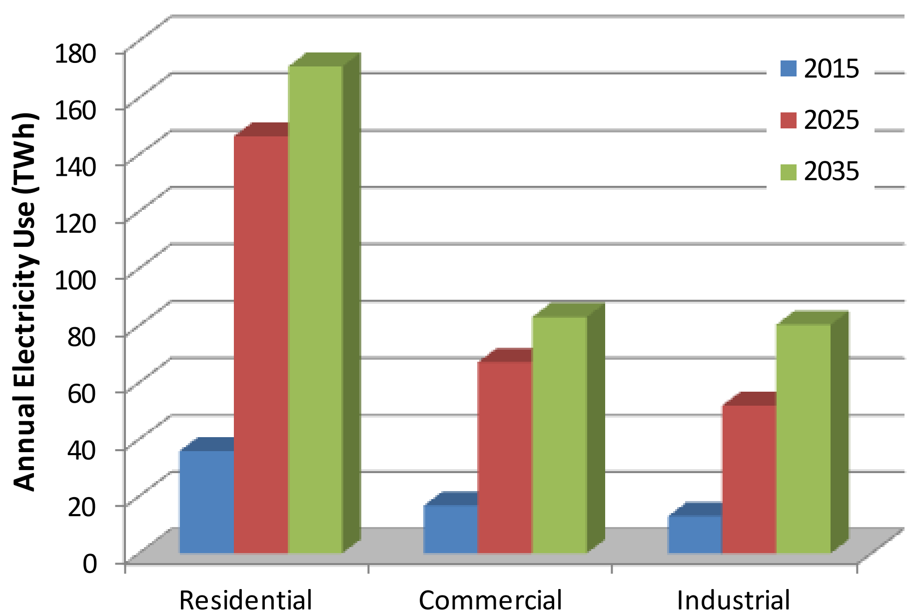


Figure 8-2
U.S. Electric Achievable Potential Load Growth, by Sector

This study did not investigate replacing fossil-fueled vehicles with plug-in electric vehicles (PEVs). The potential for PEVs has been analyzed in separate studies covered in Section 8. The results from the efficiency potential analysis, transportation electrification and electrification in the residential, commercial and industrial sectors are compared in Section 9.

The following sections discuss the approach used, and the primary energy and CO_2 savings evaluated in the 2009 electrification study. As such, all results are presented in their original form with 2009 as the base year.

Analysis Approach

Technologies considered to be generally beneficial and high efficiency were first screened to determine whether they would produce CO_2 savings when replacing their fossil-fueled counterpart. The technical potential then assumes phase-in of these most beneficial technologies as the baseline equipment turns over, and all fossil fuel is converted to electric consumption where there is a beneficial technology.

The achievable, or realistic, potential applied more conservative assumptions to each of sectors. Assumptions for the residential and commercial sectors were modified as follows:

1. The phase-in penetration of electric technologies grew at half the rate of the technical potential, and the maximum fossil fuel displacement for all end uses and technologies was 50%;

2. The efficiency of heat pump water heaters was reduced to a baseline of 2.5 COP;

3. Air-source heat pumps were used for displacement of all fossil-fueled space heating in the South and West census regions;

4. Ground-source heat pumps were used for displacement of all space heating consumption in the Northeast and Midwest as in the technical potential;

5. Air- and ground-source heat pump baseline efficiencies were near current ENERGY STAR and CEE Tier 1 ratings;

6. The efficiencies of all heat pumps used for space heating and cooling, and heat pump water heaters were assumed to increase modestly over the forecast period, with a final value less than those used in the technical potential;

7. In the residential sector electric instantaneous water heaters were used to replace half of the displaced distillate fuel oil for water heating in the Northeast (not favorable in other regions) with heat pumps displacing the rest; and

8. Fossil-fueled technology efficiencies remained the same as those in the technical potential and were constant over the forecast period.

In the industrial sector lower market shares were determined using the project team's professional experience and judgment and they reflect economic, market, societal, and attitudinal barriers that act to decrease the likelihood of technology penetration relative to the technical potential.

Energy Savings

According to *AEO2008*, total annual energy consumption for the U.S. in the residential, commercial, industrial, and transportation sectors is estimated at 102 3 quadrillion Btu in 2008, including delivered energy and energy-related losses. The Reference case forecasts this consumption to increase by 153% to 1180 quadrillion Btu in 2030, an annualized growth rate from 2008 to 2030 of 0.65%. The Reference case already accounts for market-driven efficiency improvements, and the impacts of all currently legislated federal appliance standards and building codes (including the Energy Independence and Security Act of 2007) and rulemaking procedures. It is predicated on a relatively flat electricity price forecast in real dollars between 2008 and 2030. It also assumes continued contributions of existing utility- and government-sponsored end-use energy programs established prior to 2008.

Relative to the AEO2008 Reference case, this study identifies between 1.71 and 5. 32 quadrillion Btu per year of energy savings in 2030 due to expanded end-use applications of electricity. The lower bound represents the realistic potential, while the upper bound represents the technical potential. Therefore, expanded end-use applications of electricity have the potential to reduce the annual growth rate in total energy consumption forecasted in *AEO2008* between 2008 and 2030 of 0.65% by 10% to 32%, to an annual growth rate of 0.58% to 0.44%. The lower bound of these estimated levels of energy savings are potentially achievable through voluntary fuel conversion programs implemented by utilities or similar entities. The EPRI analysis does not assume the enactment of new codes and standards beyond what is already in law. More progressive codes and standards would yield even greater levels of energy savings.

Figure 8-3 shows the share of primary energy decrease in 2030 for each end use by sector.

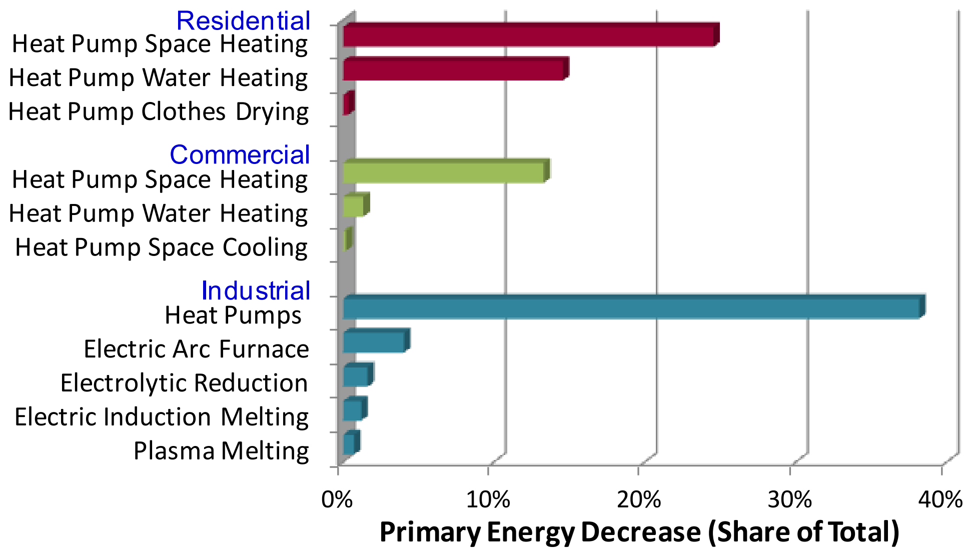


Figure 8-3
End-Use Potential for Primary Energy Decrease in 2030, by Sector

Reductions in CO_2 Emissions

According to EIA AEO 2008, annual energy-related CO_2 emissions for the U.S. in the residential, commercial, industrial, and transportation sectors is estimated at 5,983 million metric tons in 2008. The Reference case forecasts emissions to increase by 14.5% to 6,850 million metric tons in 2030, an annualized growth rate from 2008 to 2030 of 0.61 %. The Reference case is predicated on a relatively flat CO_2 intensity of the electricity generation mix between 2008 and 2030.

Relative to the EIA AEO2008 Reference case, this study identifies between 114 and 320 million metric tons per year of CO_2 emissions reductions in 2030 due to expanded end-use applications of electricity. The lower bound represents the realistic potential, while the upper bound represents the technical potential. Therefore, expanded end-use applications of electricity have the potential to reduce the annual growth rate in CO_2 emissions forecasted in EIA AEO 2008 between 2008 and 2030 of 061 % by 12% to 35%, to an annual growth rate of 0.54% to 0.40%.

The lower bound of these estimated levels of CO_2 emissions reductions are potentially achievable through voluntary fuel conversion programs implemented by utilities or similar entities. The EPRI analysis does not assume the enactment of new codes and standards beyond what is already in law, nor does it assume the CO_2 intensity of the electricity generation mix will decrease significantly in the future. More progressive codes and standards and a less carbon-intensive generation mix would yield even greater levels of CO_2 emissions reductions. Table 8-1 summarizes the technical and realistic potential results by end-use sector for the favorable[4] electric end-use technologies. The results are presented as annual values, and thus, represent the impacts for the given year – they are essentially a snapshot in time. For the technical potential, the table shows that the residential sector has the greatest promise for beneficial impacts. The commercial and industrial sectors follow with values that are roughly comparable to each other. The technical potential impacts of all three sectors combined are energy savings of 5.32 quadrillion Btu (Quads) per year and CO_2 emissions reductions of 320 million metric tons per year in 2030 relative to the baseline forecast.

In the realistic potential case, the industrial sector has the highest potential for energy savings, followed by the residential sector and then commercial sector. In regards to the realistic potential for CO_2 reductions, the residential sector holds the greatest promise, followed by the industrial sector and then the commercial sector. The realistic potential impacts of all three sectors combined are energy savings of 1.71 quadrillion Btu per year and CO_2 emissions reductions of 114 million metric tons per year in 2030 relative to the baseline forecast.

Table 8-1
Technical and Realistic Potential: Annual Impacts on Primary Energy Use and CO_2 Emissions by Sector

Technical Potential	**Decrease in Primary Energy Use(Quads)**			**Decrease in CO_2 Emissions(Million Metric Tons)**		
Sector	**2010**	**2020**	**2030**	**2010**	**2020**	**2030**
Residential	0.352	2.20	2.96	21.7	135	178
Commercial	0.118	0.72	1.09	7.75	47.2	69.1
Industrial	0.123	0.72	1.27	7.30	43.7	73.1
U.S.	**0.593**	**3.64**	**5.32**	**36.7**	**226**	**320**
Realistic Potential	**Decrease in Primary Energy Use(Quads)**			**Decrease in CO_2 Emissions(Million Metric Tons)**		
Sector	**2010**	**2020**	**2030**	**2010**	**2020**	**2030**
Residential	0.059	0.440	0.657	5.12	35.3	48.5
Commercial	0.018	0.146	0.277	1.93	13.3	21.4
Industrial	0.078	0.457	0.802	4.57	27.1	45.1
U.S.	**0.152**	**1.02**	**1.71**	**11.5**	**74.7**	**114**

Note: Numbers in table may not sum to the total due to rounding.

These estimates suggest that expanded end-use applications of electricity have the potential to reduce the annual growth rate in energy consumption forecasted in *AEO2008* between 2008 and 2030 of 0.65% by 10% to 32%, to an annual growth rate of 0.58% to 0.44%. In addition, they have the potential to reduce the annual growth rate in CO_2 emissions forecasted in the *AEO2008* between 2008 and 2030 of 0.61% by 12% to 35%, to an annual growth rate of 0.54% to 0.40%.

Under a less carbon-intensive future generation mix, more technologies would cross the line and become favorable in regards to saving energy and reducing emissions.

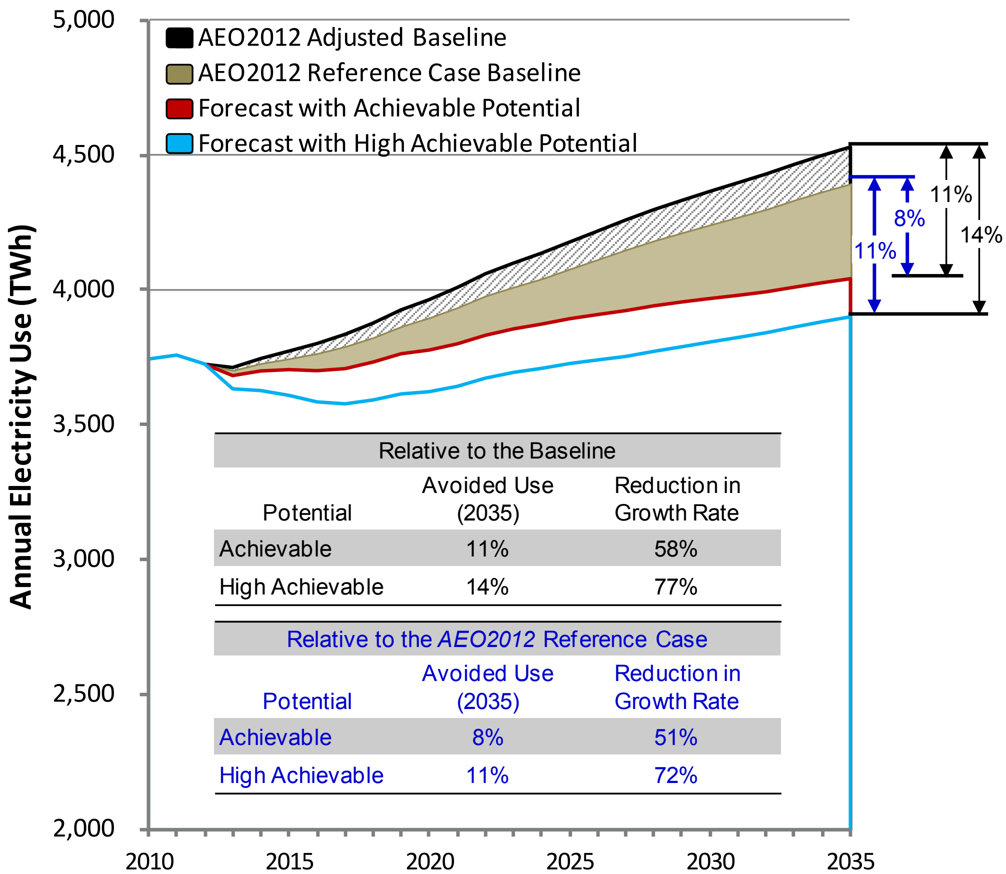
In both the residential and commercial sectors, the end-use areas with the most potential for beneficial impacts are space heating and then water heating. Clothes drying (residential) and space cooling (commercial) also exhibit potential. In the industrial sector, process heating is the predominant end-use area showing potential, followed by space heating.

Conclusion

Full deployment of all favorable electric technologies would result in an increase of delivered electricity use (in quadrillion Btu) of 1.14 by 2030, equivalent to 334 TWh. This estimate for the achievable potential for electricity growth in the end-year is presented as the 2035 potential for increased electricity consumption after shifting the original estimates to match the efficiency potential forecast period. The results of decreases due to energy efficiency along with growth in consumption from electrification are presented in Section 9.

Section 9: Conclusions

The energy savings and peak demand reductions from adoption of energy efficient technologies is significant. The application of cost-effective efficiency considering market and program barriers has the potential to reduce the annual growth rate of electricity consumption from the forecast 0.9% to 0.4%. Considering the AEO2012 Reference case forecast which includes some inherent level of efficiency, the estimates of this study represent energy and demand savings above and beyond what is expected to occur over the next 22 years. Figure 9-1 illustrates the achievable and high achievable potentials relative to the baseline forecast applied in this study and the Reference case baseline.



Relative to the Baseline		
Potential	Avoided Use (2035)	Reduction in Growth Rate
Achievable	11%	58%
High Achievable	14%	77%

Relative to the *AEO2012* Reference Case		
Potential	Avoided Use (2035)	Reduction in Growth Rate
Achievable	8%	51%
High Achievable	11%	72%

Figure 9-1
U.S. Energy Efficiency Achievable Potential

Table 9-1 presents the baseline forecasts and achievable potential in 2025 and 2035 along with the energy reduction potential relative to both baselines.

Table 9-1
Energy Efficiency Potential for the U.S.

	***AEO2012* Reference Case**	**Baseline Forecast**	**Achievable Potential**	**High Achievable Potential**
Forecasts (TWh)				
2025	4,078	4,177	3,893	3,725
2035	4,393	4,529	4,041	3,898
Savings Relative to *AEO2012* Reference Case (TWh)				
2025	-	-	185	352
2035	-	-	352	494
Savings Relative to Baseline Forecast (TWh)				
2025	-	-	284	451
2035	-	-	488	630

Although there are savings in a wide range of end uses in the residential, commercial and industrial sectors, Figure 9-2 presents the highest saving end uses in each of the sectors. Commercial indoor lighting presents significant opportunities for energy savings, more than the sum of the remaining end uses presented in Figure 9-2, and 38% of the total achievable 2035 energy savings. Lighting opportunities are also captured under the heading of industrial facilities which includes HVAC, water heating and lighting for the industrial sector.

Space cooling is in the top three for both residential and commercial where more efficient central air conditioners, room air conditioners and chillers present cost-effective energy savings above and beyond what is mandated by codes and standards.

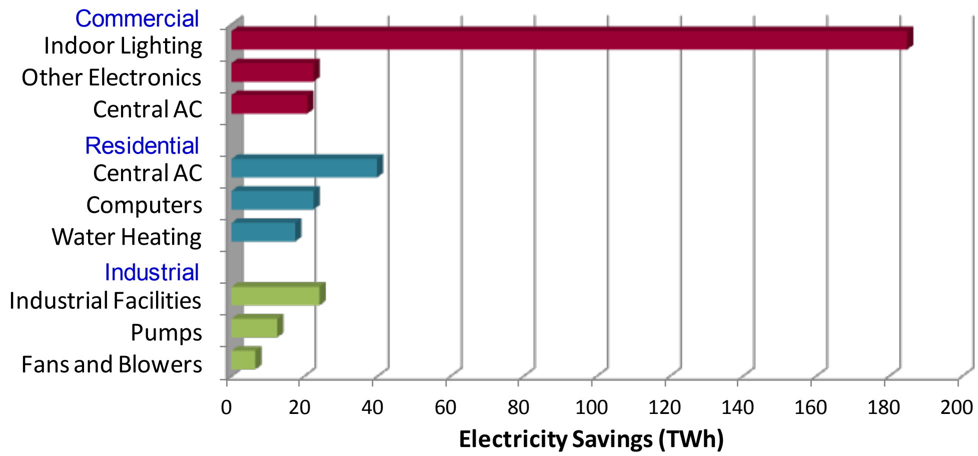


Figure 9-2
Top Three End Uses for Achievable Energy Savings, 2035

Water heating also presents the opportunity for significant savings in the residential sector for smaller units, with capacity less than 55 gallons.

The remaining heavy hitters have several common threads that will provide new opportunities for energy savings beyond what we expect to see today:

- Advanced motor technologies,
- New materials in batteries and electronics, and
- Advanced power management.

Applying the Results

The results presented in this study give insight into not only the end uses which present opportunities for energy savings through energy efficiency, but also the segments where these savings are most applicable, whether it's geographic division or building segment.

Net Impacts of Efficiency and Electrification

Forecasts for load growth vary by individual service territory and is influenced by population growth, industrial development, economic growth and many other factors. Where at points in history electricity consumption saw growth in the range of several percent, there are now places where this growth has fallen to less than a percent – as it the case with the national AEO2012 forecasts – or may be expected to decline.

With this in mind we can look for opportunities beyond energy efficiency for increasing customer value and productivity and providing benefits to society as a whole. There are other prevailing trends that are likely to impact electricity consumption including new electric end uses, digitization, and emissions regulations to name a few.

The energy savings evaluated herein represent cost-effective efficiency from the point of view of the utility, that is, the promotion of such energy efficiency is valuable to the utility. There is also value in some level of electrification, which may be fuel switching or may simply be the adoption of new electric end uses such as electric vehicles.

EPRI has done work in both of these areas to evaluate the potential for electrification, this work was not done focusing on cost-effectiveness, instead it quantified expected market trends and evaluated growth which resulted in net CO_2 reductions.

EPRI has conducted a high-level analysis of electrification potential, as well as assessment of electric transportation market trends for both light-duty vehicles and non-road transportation. Together, these analyses provide a basis for estimating the resultant increase in electricity consumption. The results of these studies are presented along with the achievable energy savings from energy efficiency are presented in Figure 9-3.

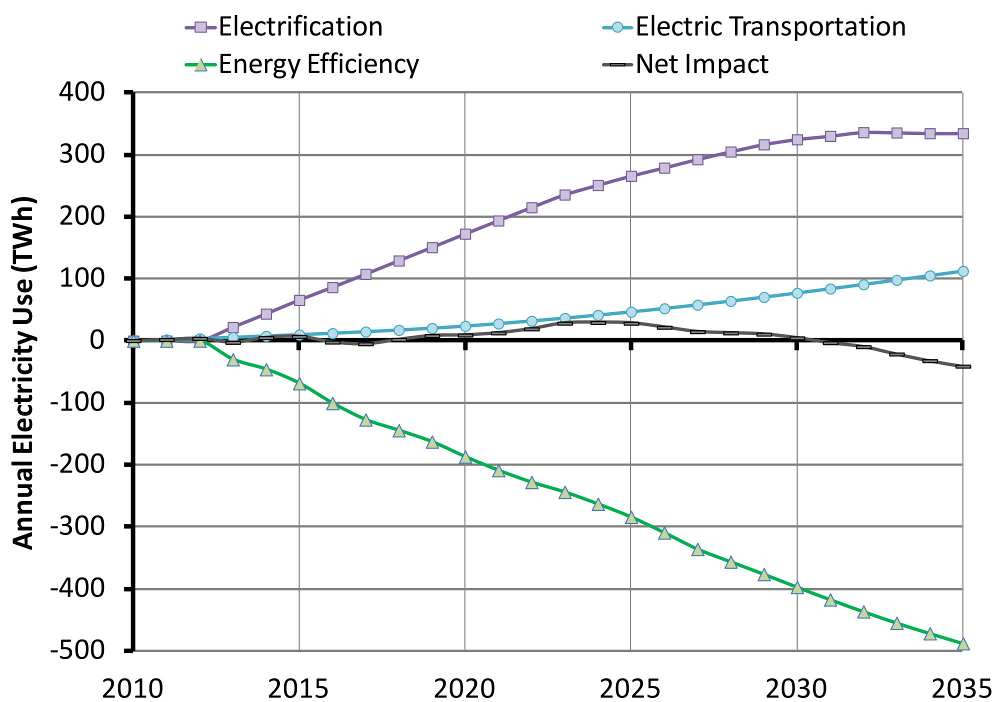


Figure 9-3
Net Impacts of Electrification and Energy Efficiency

Preliminary analysis of these three trends show that the saving achieved with energy efficiency could net the effects of increased electricity consumption through electrification. This is interesting since in all cases the energy savings or electrification is assumed to yield beneficial value to customers and society at-large. With respect to carbon emissions, reductions can be achieved through both electric efficiency and electrification. This presents expanded opportunities for utilities to increase value and productivity with one or more of these activities with a net result that could increase or decrease their forecast growth.

Follow-on Research

It is important to understand emerging trends that impact efficiency. Understanding end-use consumption and emerging technologies is key in this effort. As mentioned earlier there are key technologies that are expected to play a continuing role in energy efficiency while at the same time offering new opportunities for customer flexibility. Some key areas to consider include:

- Advanced motor technologies,
- Advanced thermal technologies such as heat pumps with expanded market potential in colder climates,
- More efficient electronics incorporating advanced materials, batteries and power management,
- Emerging electric end-use categories such as smart phones and tablets, and electric transportation.

Codes and standards continue to identify new areas for energy efficiency efforts and at the same time new end-uses continue to emerge creating new opportunities for energy savings. As the technology landscape unfolds the realm of cost-effective efficiency will also continue to evolve.

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Appendix A: Northeast Census Region Results

The Northeast is the smallest of the four Census regions in terms of geographic size and electricity use. In 2012, total electricity use is 488 TWh. Figure A-1 shows the breakdown by sector of the electricity forecast. The largest sector is commercial with 43% of the total in 2012. Residential accounts for 37%.

By 2035, total use is expected to be 514 TWh, a 5% increase over 2012 and implying a modest growth rate of 0.2% per year. The commercial sector grows the fastest during the forecast period at a rate of 0.7%, while the residential sector grows at 0.3% per year and the industrial sector declines at a rate of -1.2% per year. The breakdown of consumption for the constituent divisions – New England and Middle Atlantic – along with their share of the Northeast forecast by sector is shown in Table A-1. New England accounts for about 25% of Northeast consumption throughout the forecast.

Total achievable potential in 2035 for electricity savings through energy-efficiency programs ranges from 55 to 67 TWh, which equates to 11-13% of total load in that year as shown in Figure A-2. Figure A-3 shows the achievable potential savings by sector. In terms of the share of total load that can be saved by 2035, the commercial sector represents the greatest opportunity in the short term and over the forecast period. Table A-2 shows the total absolute achievable potential for the Northeast and the shares of this total by division and sector within each division.

Figure A-4 presents the residential baseline and achievable potential forecasts by end use. In the baseline forecast, the fastest growing end uses are heat pumps and computers, while lighting declines as a result of the EISA legislation. Growth in the remaining end uses varies. Energy efficiency savings in this sector will come from actions across several end uses: home electronics, air conditioning, lighting, space heating and water heating. There is little savings opportunity in residential appliances, with the exception of dishwashers and clothes dryers.

The commercial sector, in contrast, grows more rapidly and the potential for savings is concentrated in a few end uses. Figure A-5 presents the commercial-sector baseline and achievable potential forecasts by end use. Baseline growth is driven largely by growth in office equipment and "other" uses. Achievable energy-efficiency savings are dominated by opportunities in lighting, office equipment and cooling, which together account for 39 TWh savings in 2035.

The industrial sector is in decline, yet continues to have considerable opportunity for efficiency savings in the industrial facilities end use. Figure A-6 presents the industrial sector baseline and achievable potential forecasts by end use.

To put the end-use and sector-level potential in perspective, Figure A-7 shows the top 10 end uses in the Northeast's achievable potential. These results parallel the findings for the U.S. as a whole. Finally, Figures A-8 and A-9 present the potential for summer and winter peak coincident demand savings respectively. For the Northeast, the achievable range in summer is 10-14% in 2035, and in winter is 11-15% similar to the 10-16% range for the U.S. as a whole.

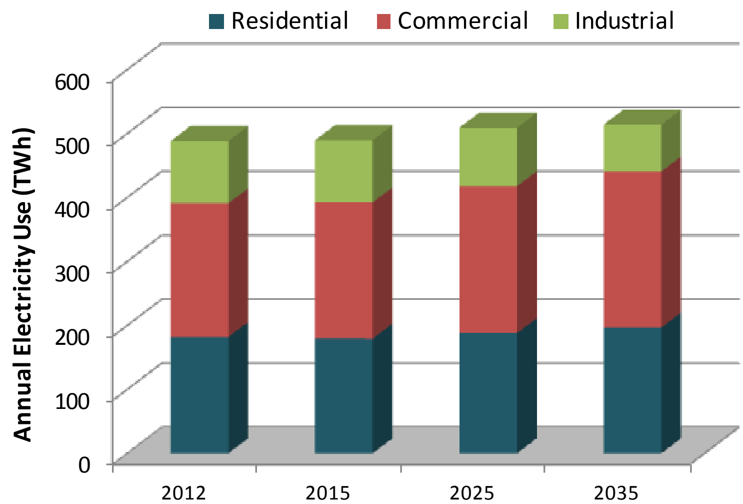

Figure A-1
Electricity Forecast by Sector – Northeast Census Region

Table A-1
Electricity Forecast by Division and Sector - Northeast

	2012	**2015**	**2025**	**2035**
New England (GWh)	123,949	124,112	128,848	128,928
Sector Share of Division				
Residential	38%	38%	38%	39%
Commercial	38%	39%	41%	44%
Industrial	23%	24%	21%	17%
Middle Atlantic (GWh)	364,219	365,325	379,991	384,864
Sector Share of Division				
Residential	37%	36%	37%	38%
Commercial	44%	45%	47%	49%
Industrial	19%	19%	17%	13%

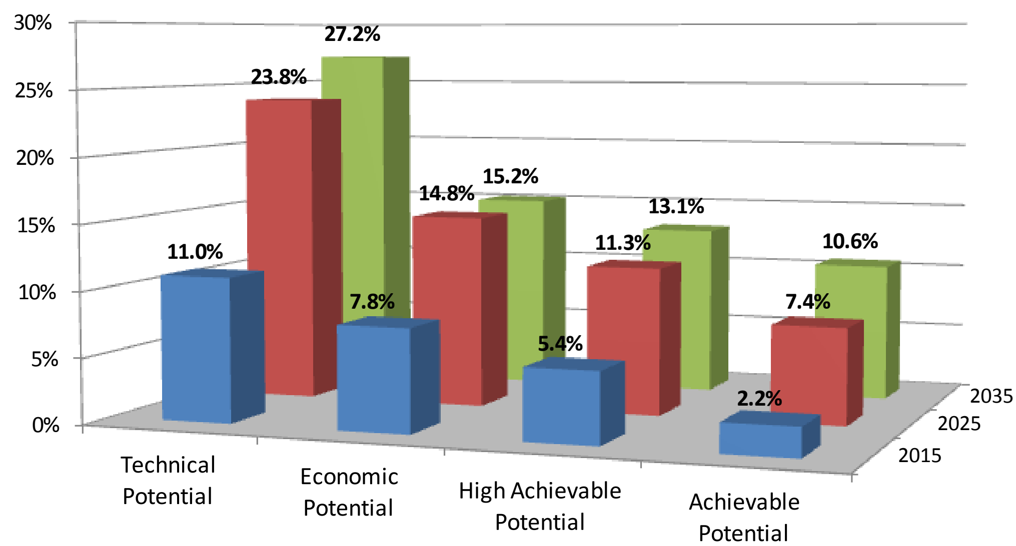

Figure A-2
Energy Efficiency Potential – Northeast Census Region

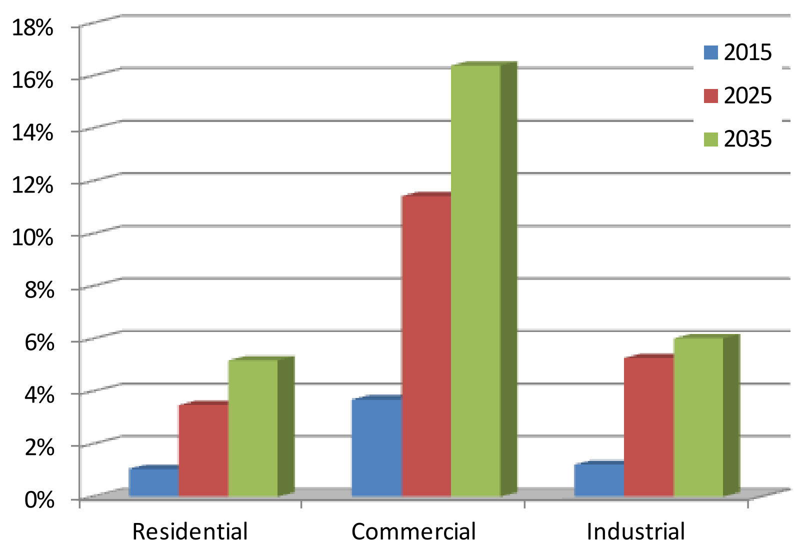

Figure A-3
Achievable Potential by Sector (as a Percentage of Sector Baseline) – Northeast Census Region

Table A-2
Share of Achievable Potential by Sector and Division - Northeast

	2015	2025	2035
Northeast Total (GWh)	10,931	37,588	54,568
Residential	5%	5%	5%
Commercial	19%	16%	17%
Industrial	3%	4%	2%
New England Total	**27%**	**25%**	**25%**
Residential	13%	13%	14%
Commercial	53%	54%	56%
Industrial	8%	9%	6%
Middle Atlantic Total	**73%**	**75%**	**75%**

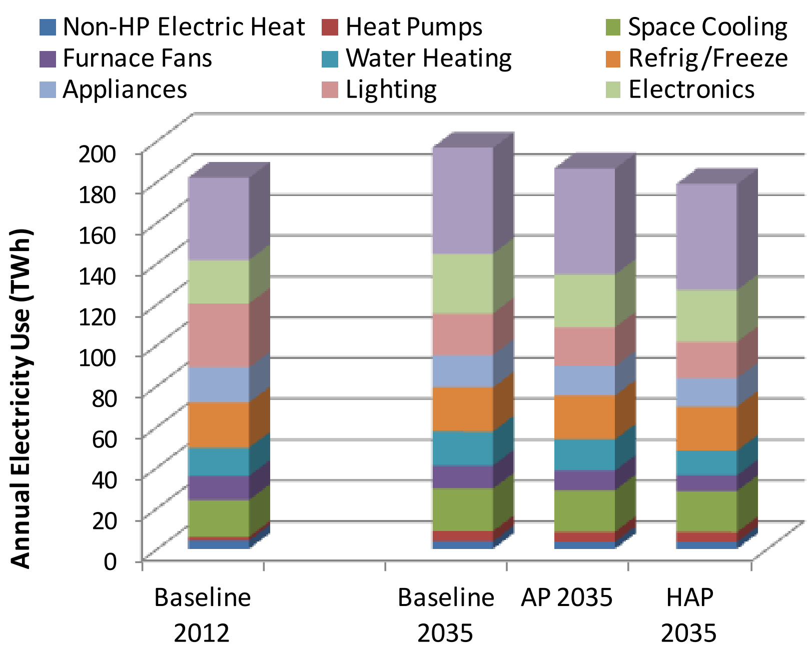

Figure A-4
Residential Baseline and Achievable Potential by End Use - Northeast

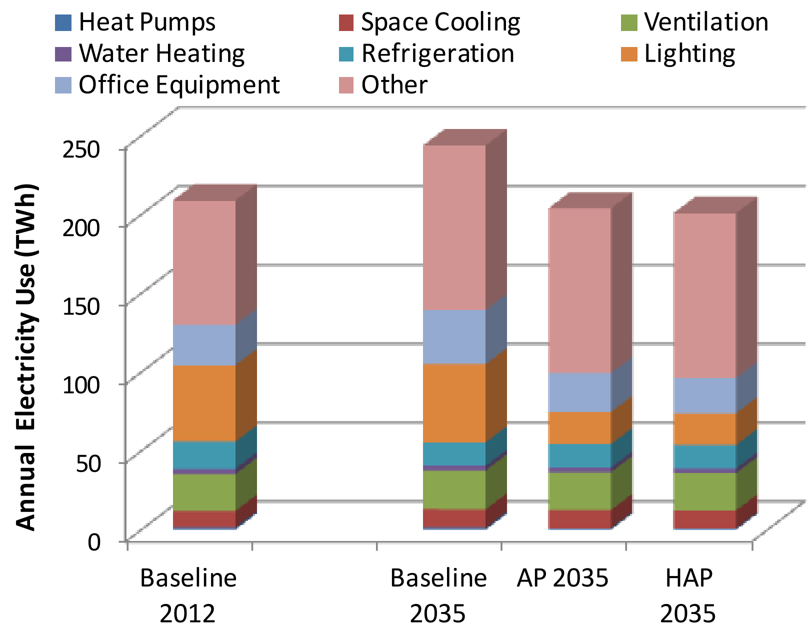

Figure A-5
Commercial Baseline and Achievable Potential by End Use - Northeast

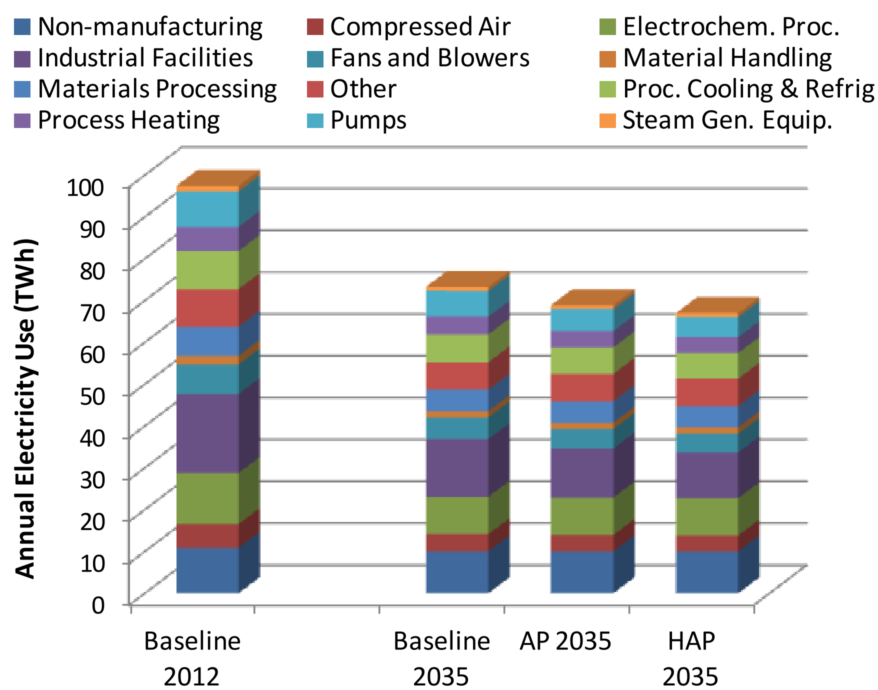

Figure A-6
Industrial Baseline and Achievable Potential by End Use - Northeast

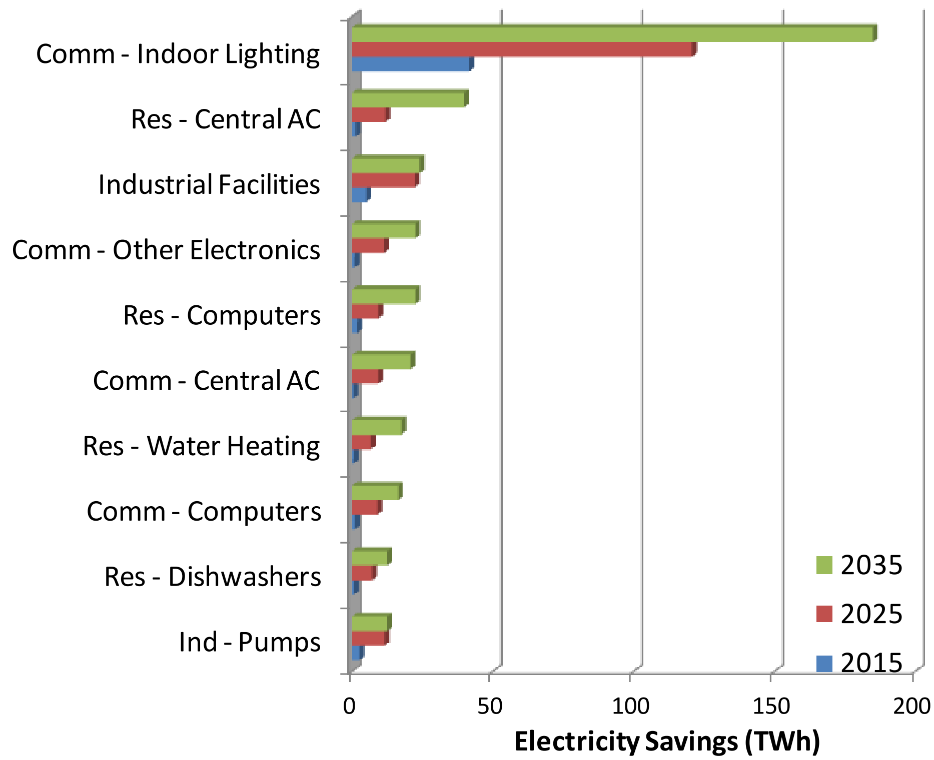

Figure A-7
Achievable Potential Top 10 End Uses – Northeast Census Region

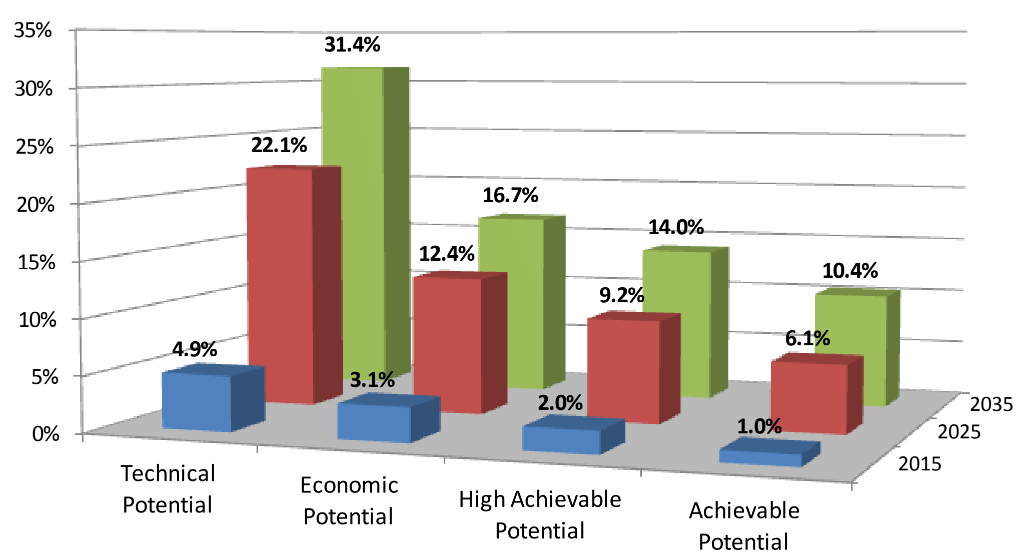

Figure A-8
Summer Peak Coincident Demand Potential – Northeast Region

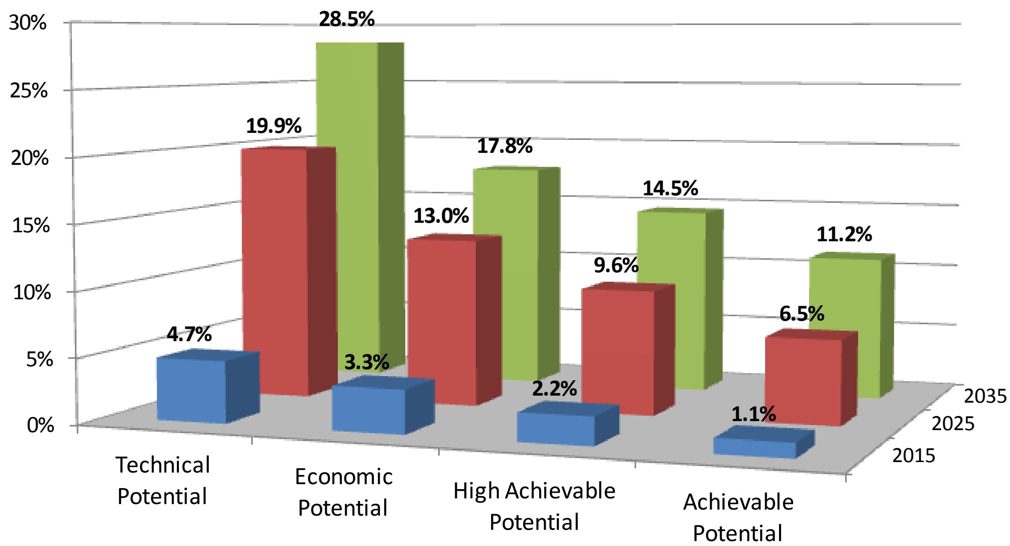

Figure A-9
Winter Peak Coincident Demand Potential – Northeast Region

Appendix B: South Census Region Results

The South is the largest region in terms of electricity use. In 2012, total electricity use is 1,701 TWh. Figure B-1 shows the breakdown by sector of the electricity forecast. The largest sector is residential with 41% of the total in 2012. Commercial accounts for 34%.

By 2035, total use is expected to be 2,191 TWh, a 29% increase over 2012 and implying a moderate growth rate of 1.1% per year. The residential sector grows the fastest during the forecast period at a rate of 1.4%, while the commercial sector grows at 1.3% per year and the industrial at a rate of 0.3% per year. The breakdown of consumption for the constituent divisions – South Atlantic, Florida, East South Central, West South Central, and Texas – along with their share of the South forecast by sector is shown in Table B-1. South Atlantic accounts for between 33% of South consumption throughout the forecast.

Total achievable potential in 2035 for electricity savings through energy-efficiency programs ranges from 262 to 348 TWh, which equates to 12-16% of total load in that year as shown in Figure B-2. Figure B-3 shows the achievable potential savings by sector. In terms of the share of total load that can be saved by 2035, the commercial sector represents the greatest opportunity in the short term and over the forecast period. Table B-2 shows the total absolute achievable potential for the South and the shares of this total by division and sector within each division.

Figure B-4 presents the residential baseline and achievable potential forecasts by end use. In the baseline forecast, the fastest growing end uses are heat pumps and computers, while lighting declines as a result of the EISA legislation. Room AC also shows decline, higher than lighting, over the forecast period, while clothes dryers have a slight decline. Growth in the remaining end uses is moderate. Energy efficiency savings in this sector will come from actions across several end uses: home electronics, appliances, lighting, space heating and water heating. Reductions from space cooling measures present significant savings potential, accounting for more than a third of the achievable potential.

In the commercial sector the majority of the potential for savings is concentrated in a few end uses. Figure B-5 presents the commercial-sector baseline and achievable potential forecasts by end use. Baseline growth is driven largely by growth in office equipment and "other" uses. Achievable energy-efficiency savings are dominated by opportunities in lighting, office equipment and cooling, which together account for 133 TWh savings in 2035.

Slight growth is expected in the industrial sector, yet continues to have considerable opportunity for efficiency savings in the industrial facilities end use. Figure B-6 presents the industrial sector baseline and achievable potential forecasts by end use.

To put the end-use and sector-level potential in perspective, Figure B-7 shows the top 10 end uses in the South's achievable potential. As expected space heating and cooling have a higher potential for savings in the South than in the other regions. Finally, Figure B-8 and Figure B-9 present the potential for summer and winter peak coincident demand savings respectively. For the South, the achievable range in summer is 13-19% in 2035, and in winter is 10-15%, where the summer savings are slightly higher than the summer savings for the U.S. as a whole (11-16%). This reflects the increased potential for savings in space cooling.

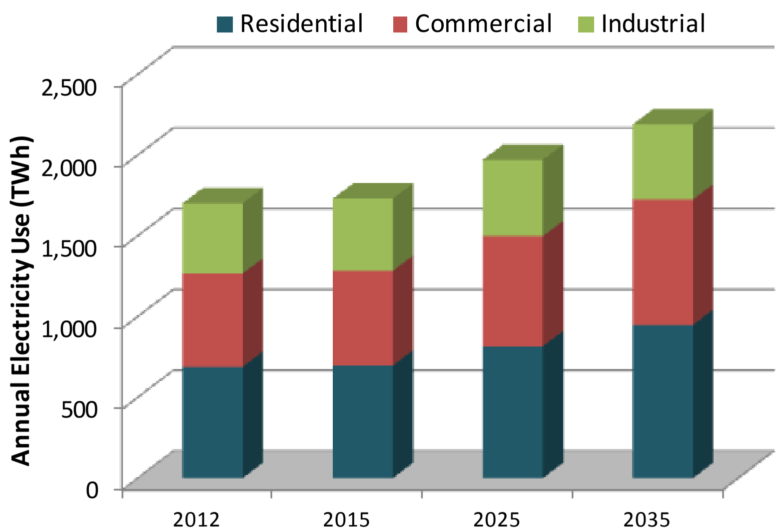

Figure B-1
Electricity Forecast by Sector – South Census Region

Table B-1
Electricity Forecast by Division and Sector - South

	2012	2015	2025	2035
South Atlantic (GWh)	536,393	546,989	635,746	720,519
Sector Share of Division				
Residential	44%	44%	45%	46%
Commercial	38%	38%	39%	39%
Industrial	18%	18%	17%	14%
Florida (GWh)	267,330	272,611	316,846	359,096
Sector Share of Division				
Residential	44%	44%	45%	46%
Commercial	38%	38%	39%	39%
Industrial	18%	18%	17%	14%
East South Central (GWh)	329,657	336,383	376,291	407,169
Sector Share of Division				
Residential	37%	37%	38%	40%
Commercial	25%	25%	26%	27%
Industrial	38%	38%	36%	33%
West South Central (GWh)	193,485	195,532	218,885	239,814
Sector Share of Division				
Residential	37%	37%	39%	40%
Commercial	34%	33%	34%	34%
Industrial	29%	30%	28%	25%
Texas (GWh)	374,603	378,566	423,779	464,299
Sector Share of Division				
Residential	37%	37%	39%	40%
Commercial	34%	33%	34%	34%
Industrial	29%	30%	28%	25%

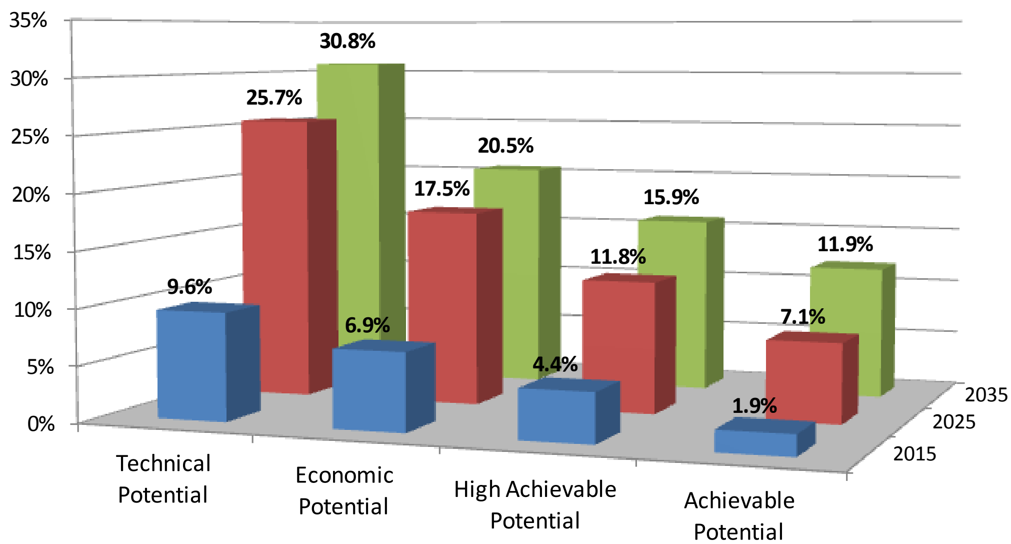

Figure B-2
Energy Efficiency Potential – South Census Region

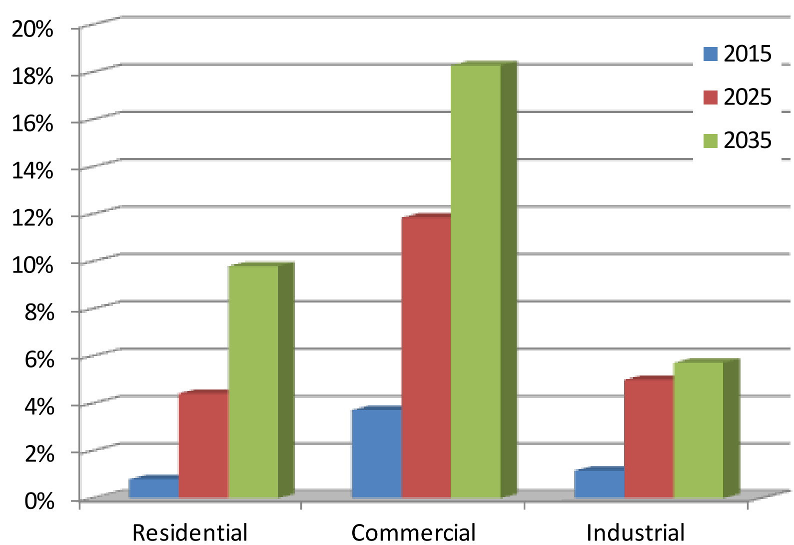

Figure B-3
Achievable Potential by Sector (as a Percentage of Sector Baseline) – South Census Region

Table B-2
Share of Achievable Potential by Sector and Division - South

	2015	2025	2035
South Total (GWh)	32,489	140,476	261,578
Residential	6%	8%	11%
Commercial	28%	22%	21%
Industrial	4%	4%	2%
South Atlantic Total	**38%**	**34%**	**34%**
Residential	3%	5%	7%
Commercial	14%	11%	10%
Industrial	2%	2%	1%
Florida Total	**19%**	**18%**	**19%**
Residential	2%	4%	4%
Commercial	7%	6%	6%
Industrial	5%	5%	3%
East South Central Total	**14%**	**15%**	**13%**
Residential	2%	3%	4%
Commercial	6%	6%	6%
Industrial	2%	2%	1%
West South Central Total	**10%**	**11%**	**11%**
Residential	4%	6%	9%
Commercial	12%	12%	11%
Industrial	4%	4%	3%
Texas Total	**19%**	**22%**	**23%**

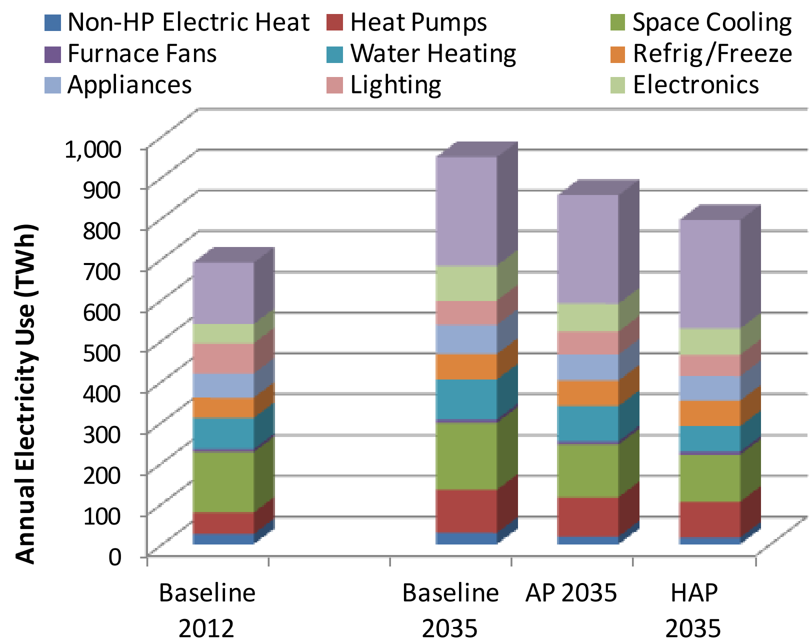

Figure B-4
Residential Baseline and Achievable Potential by End Use – South

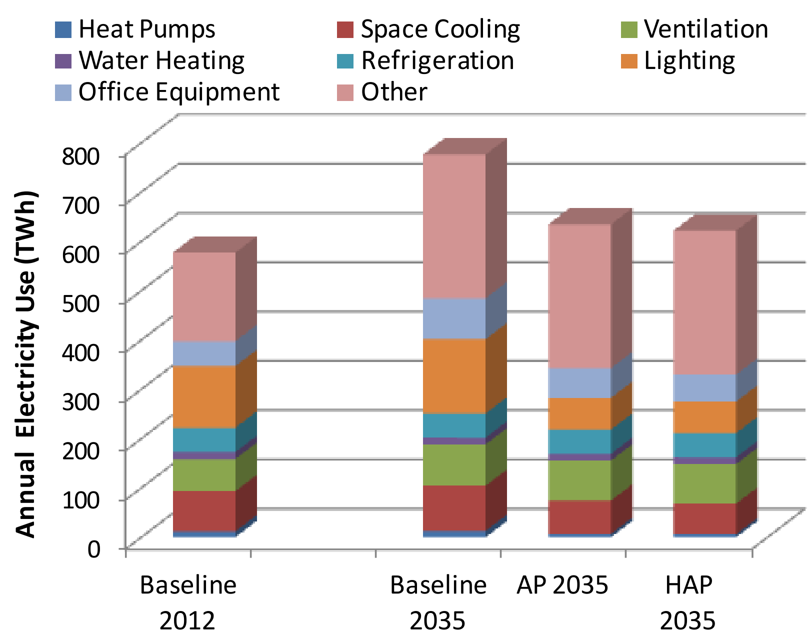

Figure B-5
Commercial Baseline and Achievable Potential by End Use - South

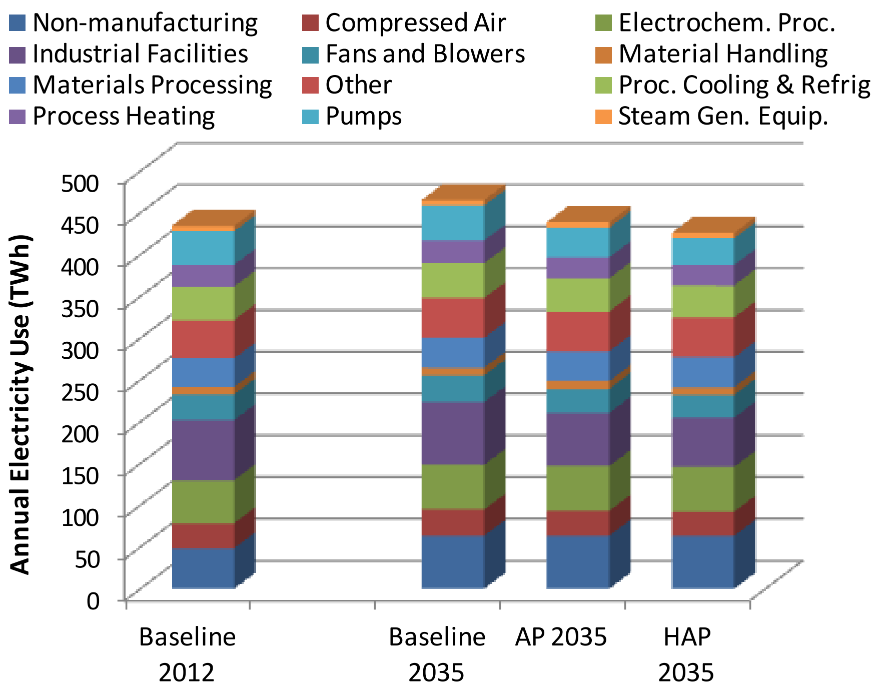

Figure B-6
Industrial Baseline and Achievable Potential by End Use - South

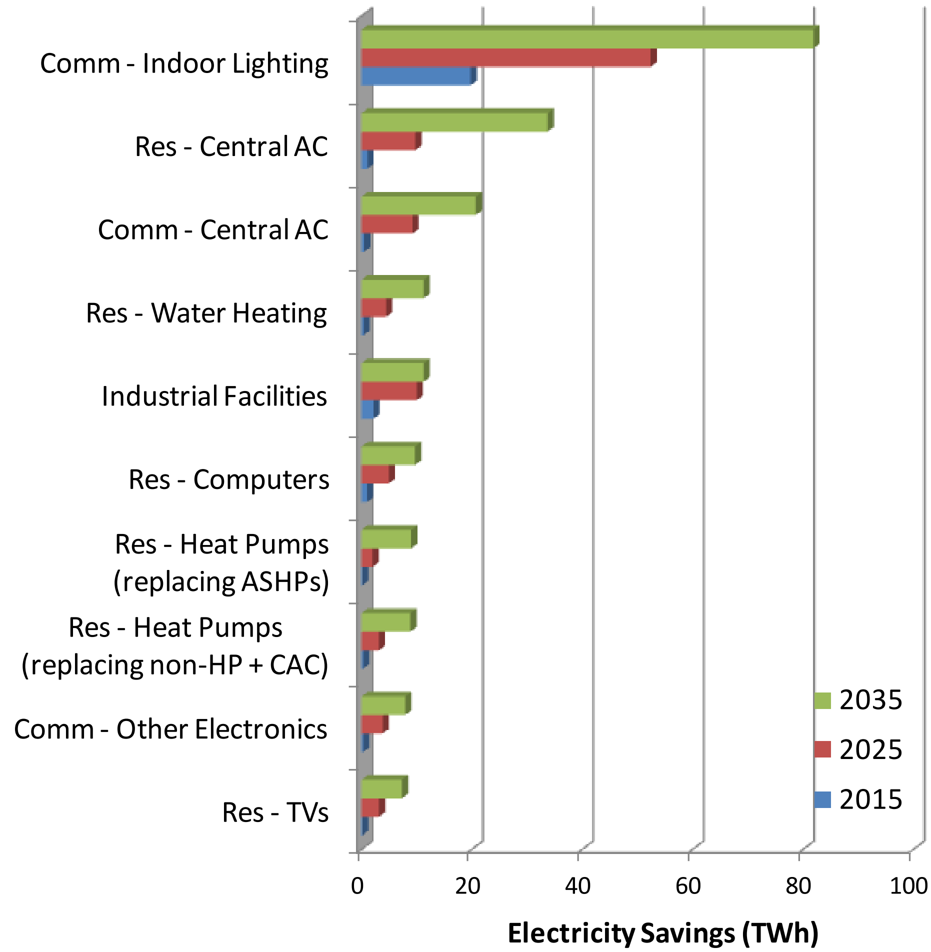

Figure B-7
Achievable Potential Top 10 End Uses – South Census Region

Note: Residential heat pumps have potential for savings replacing both air-source heat pumps (ASHPs) and replacing a non-heat pump electric heating unit plus a central AC (non-HP + CAC)

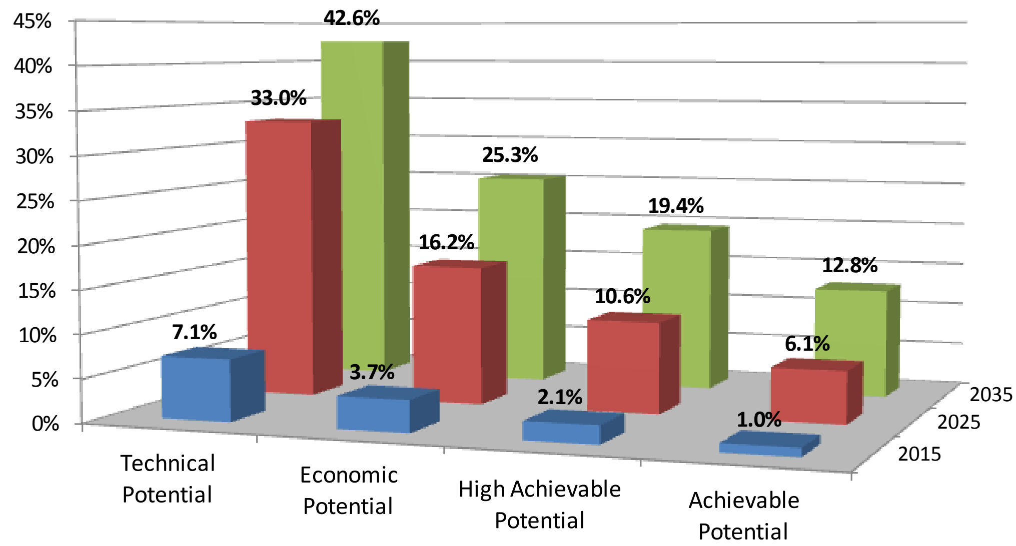

Figure B-8
Summer Peak Coincident Demand Potential – South Region

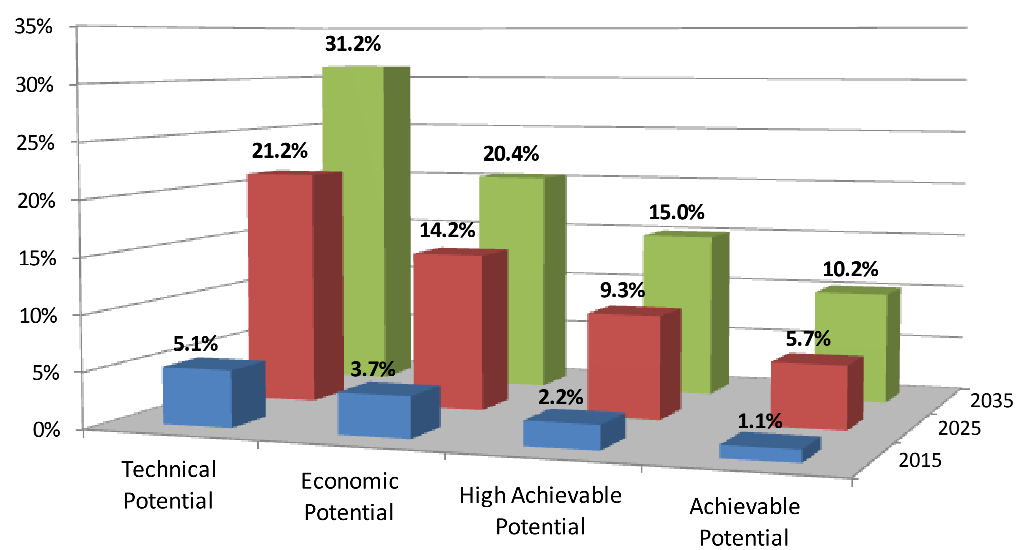

Figure B-9
Winter Peak Coincident Demand Potential – South Region

Appendix C: Midwest Census Region Results

The Midwest is the second largest of the four Census regions in terms of electricity use. In 2012, total electricity use is 862 TWh. Figure C-1 shows the breakdown by sector of the electricity forecast. The sector shares of Midwest load are nearly equal across the forecast period.

By 2035, total use is expected to be 947 TWh, a 10% increase over 2012 and implying a modest growth rate of 0.4% per year. The commercial sector grows the fastest during the forecast period at a rate of 1.1%, while the residential sector grows at 0.5% per year and the industrial sector declines at a rate of -0.5% per year. The breakdown of consumption for the constituent divisions – East North Central and West North Central – along with their share of the Midwest forecast by sector is shown in Table C-1. East North Central accounts for about 66% of Midwest consumption throughout the forecast.

Total achievable potential in 2035 for electricity savings through energy-efficiency programs ranges from 85 to 105 TWh, which equates to 9-11% of total load in that year as shown in Figure C-2. Figure C-3 shows the achievable potential savings by sector. In terms of the share of total load that can be saved by 2035, the commercial sector represents the greatest opportunity in the short term and over the forecast period. Although, compared to the other regions commercial savings as a percent of the commercial baseline are slightly lower. Table C-2 shows the total absolute achievable potential for the Midwest and the shares of this total by division and sector within each division.

Figure C-4 presents the residential baseline and achievable potential forecasts by end use. In the baseline forecast, the fastest growing end uses are ground-source heat pumps and computers, while lighting declines as a result of the EISA legislation. Growth in remaining end uses varies with decline in clothes dryers and other appliances except refrigerators. Energy savings in this sector will come from actions across several end uses: home electronics, air conditioning, lighting, space heating and water heating. There is little opportunity for savings in residential appliances, except clothe dryers and dishwashers.

The commercial sector, in contrast, grows more rapidly and the potential for savings is concentrated in a few end uses. Figure C-5 presents the commercial-sector baseline and achievable potential forecasts by end use. Baseline growth is driven largely by growth in office equipment and “other” uses. Achievable energy-efficiency savings are dominated by opportunities in lighting and office equipment, which together account for 53 TWh savings in 2035.

The industrial sector is in decline, yet continues to have considerable opportunity for efficiency savings in the industrial facilities end use. Figure C-6 presents the industrial sector baseline and achievable potential forecasts by end use.

To put the end-use and sector-level potential in perspective, Figure C-7 shows the top 10 end uses in the Midwest's achievable potential. These results differ slightly from the findings for the U.S. as a whole. Finally, Figure C-8 and Figure C-9 present the potential for summer and winter peak coincident demand savings respectively. For the Midwest, the achievable range in summer is 9-12% in 2035, and in winter is 9-13%, slightly lower than the U.S. as a whole.

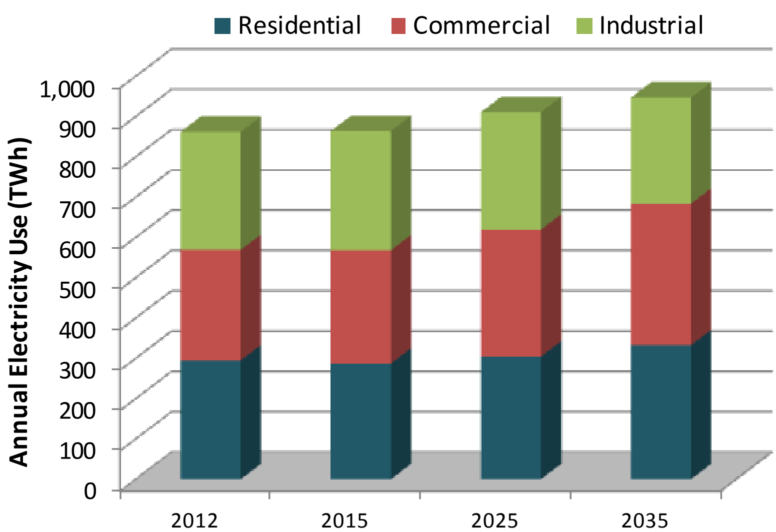

Figure C-1
Electricity Forecast by Sector – Midwest Census Region

Table C-1
Electricity Forecast by Division and Sector - Midwest

	2012	2015	2025	2035
East North Central (GWh)	571,584	573,100	598,173	615,818
Sector Share of Division				
Residential	33%	32%	32%	33%
Commercial	31%	32%	34%	38%
Industrial	36%	36%	34%	30%
West North Central (GWh)	290,595	290,925	312,967	331,313
Sector Share of Division				
Residential	36%	36%	37%	40%
Commercial	34%	34%	35%	36%
Industrial	30%	30%	28%	24%

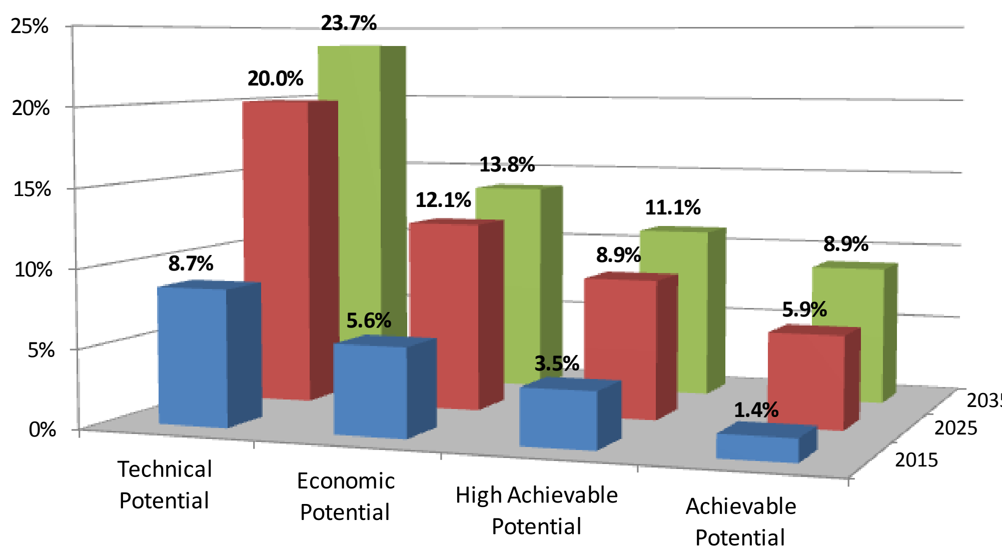

Figure C-2
Energy Efficiency Potential – Midwest Census Region

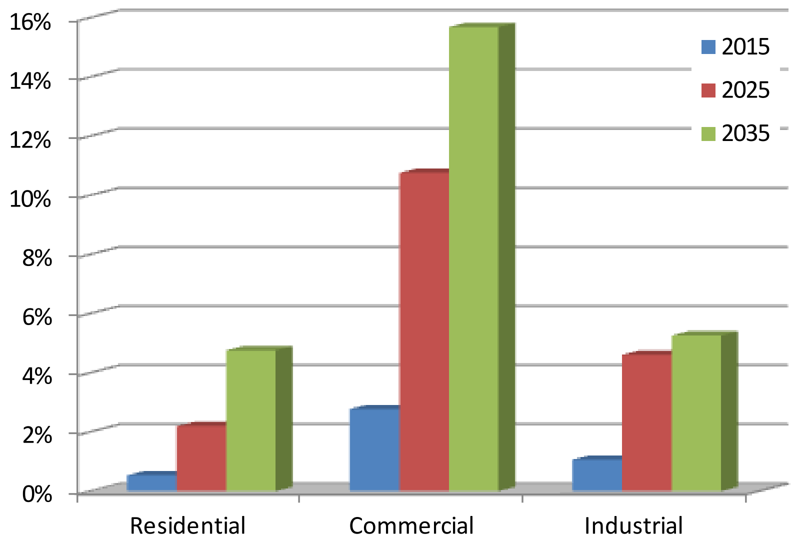

Figure C-3
Achievable Potential by Sector (as a Percentage of Sector Baseline) – Midwest Census Region

Table C-2
Share of Achievable Potential by Sector and Division - Midwest

	2015	**2025**	**2035**
Midwest Total (GWh)	12,482	53,957	84,762
Residential	6%	6%	10%
Commercial	44%	46%	48%
Industrial	18%	17%	11%
East North Central Total	**67%**	**70%**	**69%**
Residential	6%	6%	8%
Commercial	19%	17%	17%
Industrial	8%	8%	5%
West North Central Total	**33%**	**30%**	**31%**

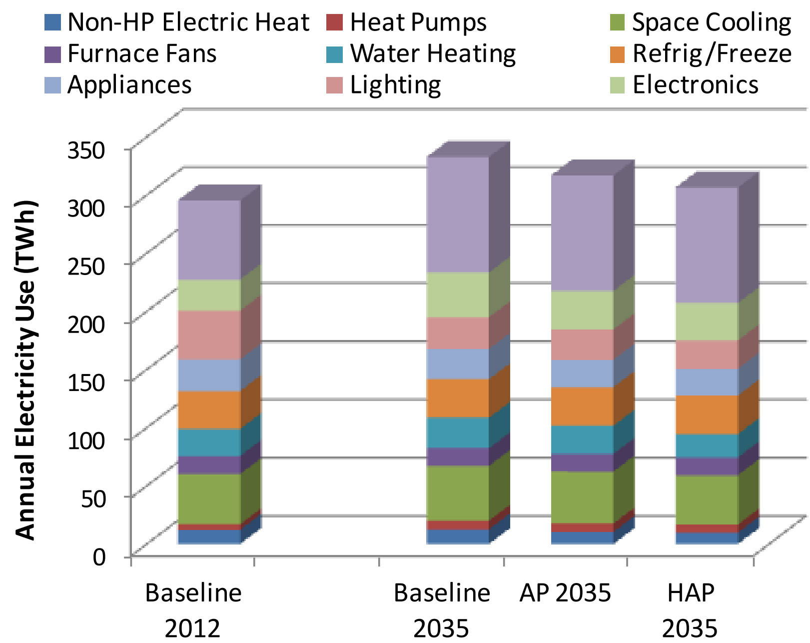

Figure C-4
Residential Baseline and Achievable Potential by End Use - Midwest

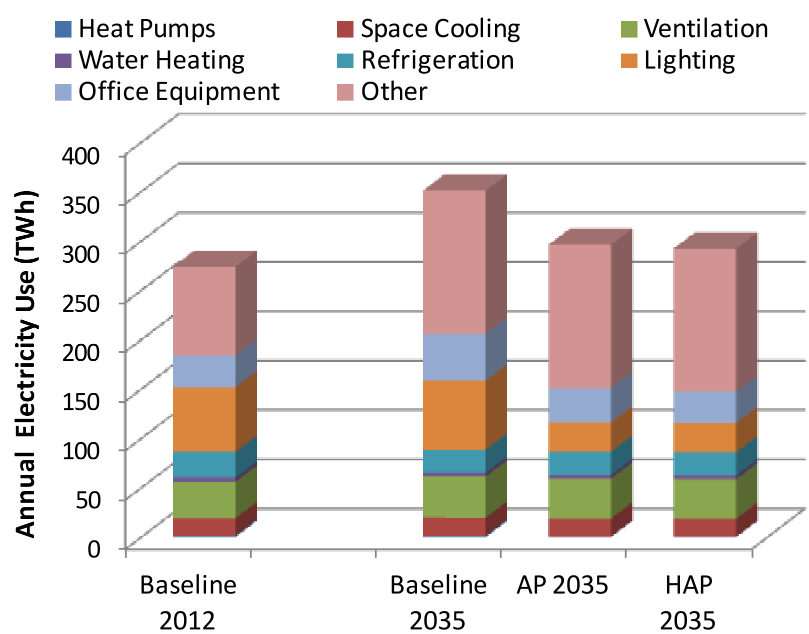

Figure C-5
Commercial Baseline and Achievable Potential by End Use - Midwest

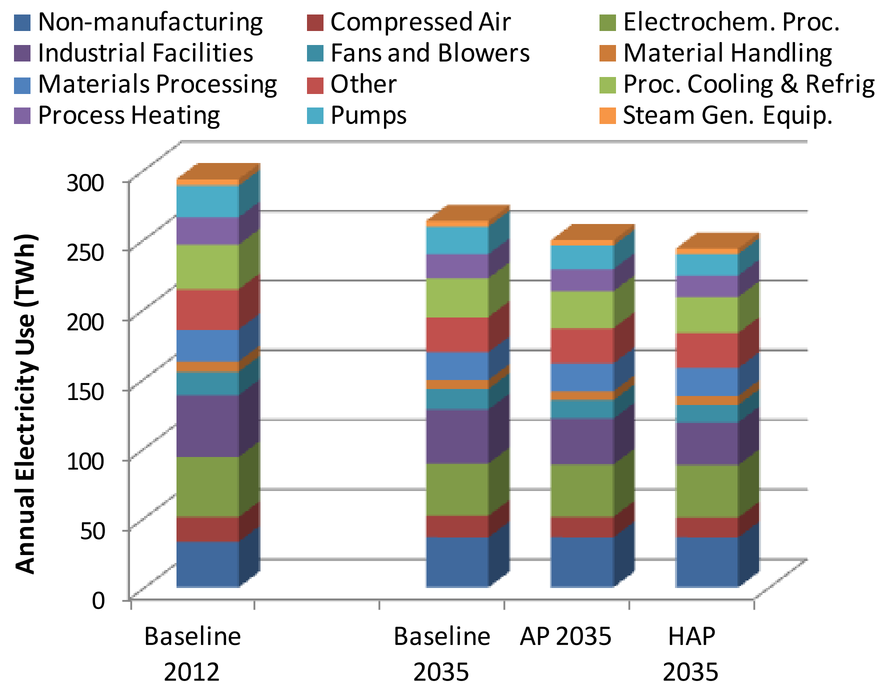

Figure C-6
Industrial Baseline and Achievable Potential by End Use - Midwest

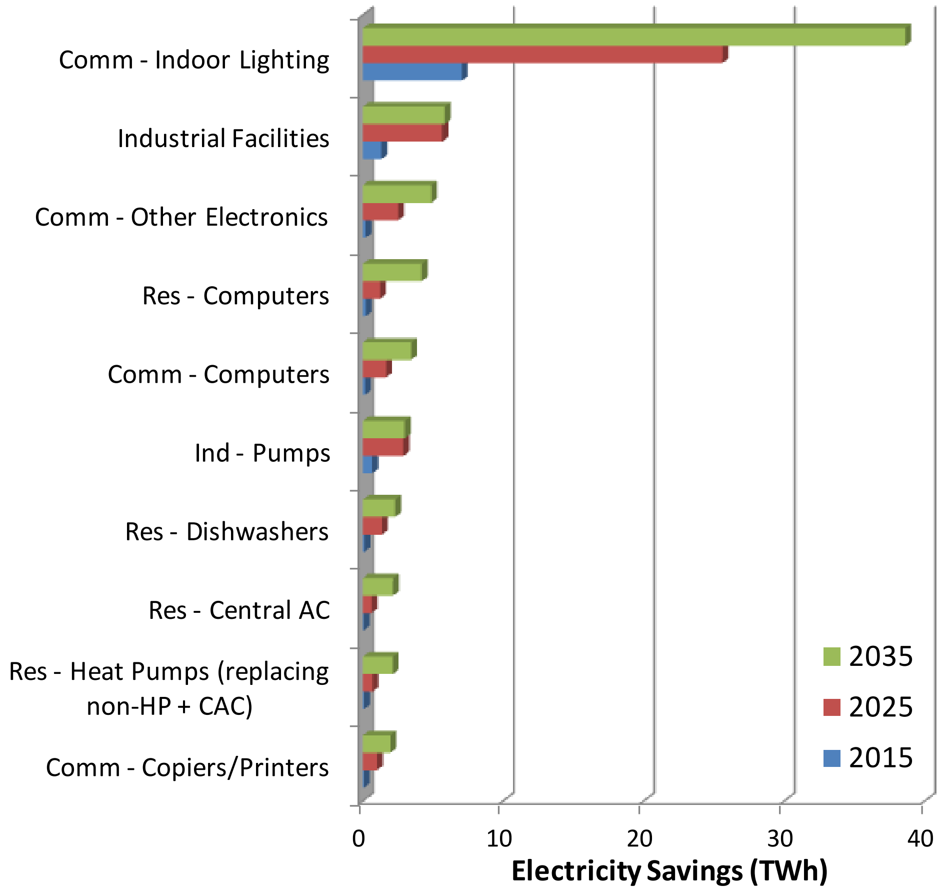

Figure C-7
Achievable Potential Top 10 End Uses – Midwest Census Region

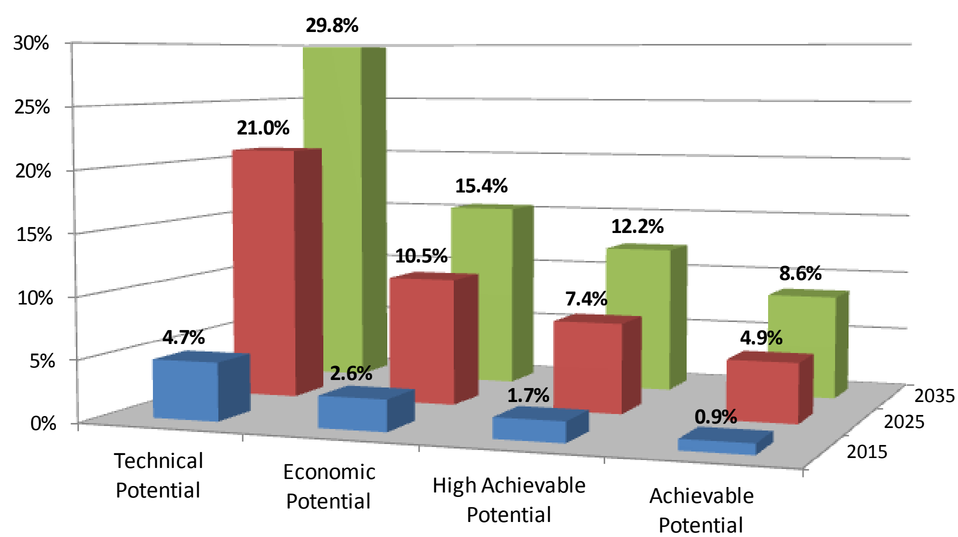

Figure C-8
Summer Peak Coincident Demand Potential – Midwest Region

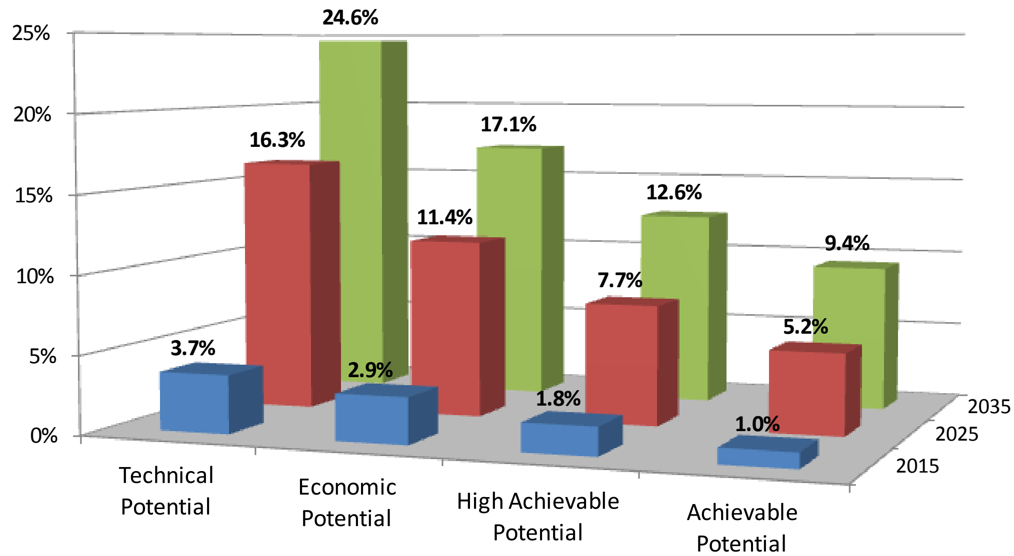

Figure C-9
Winter Peak Coincident Demand Potential – Midwest Region

Appendix D: West Census Region Results

The West is the second smallest of the four Census regions in terms of electricity use. In 2012, total electricity use is 672 TWh. Figure D-1 shows the breakdown by sector of the electricity forecast. The largest sector is commercial with 39% of the total in 2012. Residential accounts for 37%.

By 2035, total use is expected to be 877 TWh, a 30% increase over 2012 and implying a moderate growth rate of 1.2% per year. The commercial sector grows the fastest during the forecast period at a rate of 1.5%, while the residential sector grows at 1.2% per year and the industrial at a rate of 0.4% per year. The breakdown of consumption for the constituent divisions – Mountain North, Mountain South, Pacific, and California– along with their share of the West forecast by sector is shown in Table D-1. California accounts for about 35% of West consumption throughout the forecast.

Total achievable potential in 2035 for electricity savings through energy-efficiency programs ranges from 87 to 110 TWh, which equates to 10-13% of total load in that year as shown in Figure D-2. Figure D-3 shows the achievable potential savings by sector. In terms of the share of total load that can be saved by 2035, the commercial sector represents the greatest opportunity in the short term and over the forecast period. Table D-2 shows the total absolute achievable potential for the West and the shares of this total by division and sector within each division.

Figure D-4 presents the residential baseline and achievable potential forecasts by end use. In the baseline forecast, the fastest growing end uses are heat pumps and computers, while lighting declines as a result of the EISA legislation. There is slight decline in non-heat pump electric heating and otherwise moderate growth is forecast for most end uses. Energy efficiency savings in this sector will come from actions across several end uses: home electronics, air conditioning, lighting, space heating and water heating. Aside from dishwashers and clothes dryers appliances contribute little to achievable savings.

The commercial sector, in contrast, grows more rapidly and the potential for savings is concentrated in a few end uses. Figure D-5 presents the commercial-sector baseline and achievable potential forecasts by end use. Baseline growth is driven largely by growth in office equipment and "other" uses. Achievable energy-efficiency savings are dominated by opportunities in lighting, office equipment and cooling, which together account for 54 TWh savings in 2035.

The industrial sector sees little growth, yet continues to have considerable opportunity for efficiency savings in the industrial facilities end use. Figure D-6 presents the industrial sector baseline and achievable potential forecasts by end use.

To put the end-use and sector-level potential in perspective, Figure D-7 shows the top ten end uses in the West's achievable potential. These differ from the U.S. as a whole with little savings in commercial cooling, and commercial outdoor street and area lighting making into the top ten. Finally, Figure D-8 and Figure D-9 present the potential for summer and winter peak coincident demand savings respectively. For the West, the achievable range in both winter and summer is 10-14% in 2035 slightly lower than the 10-16% range for the U.S. as a whole.

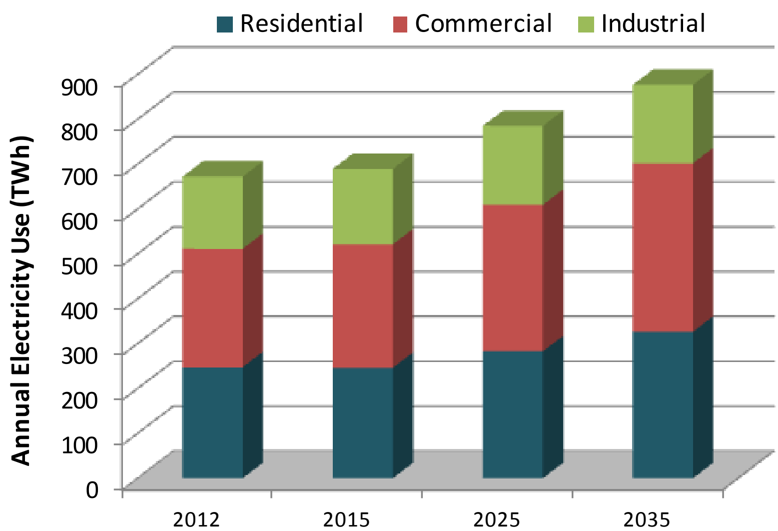

Figure D-1
Electricity Forecast by Sector – West Census Region

Table D-1
Electricity Forecast by Division and Sector - West

	2012	2015	2025	2035
Mountain North (GWh)	120,885	124,870	146,264	165,642
Sector Share of Division				
Residential	37%	36%	38%	41%
Commercial	35%	36%	37%	37%
Industrial	28%	28%	25%	22%
Mountain South (GWh)	143,531	148,262	173,665	196,672
Sector Share of Division				
Residential	37%	36%	38%	41%
Commercial	35%	36%	37%	37%
Industrial	28%	28%	25%	22%
Pacific (GWh)	166,520	169,953	190,069	210,193
Sector Share of Division				
Residential	37%	35%	35%	35%
Commercial	42%	43%	45%	47%
Industrial	21%	22%	21%	19%
California (GWh)	241,219	246,192	275,332	304,483
Sector Share of Division				
Residential	37%	35%	35%	35%
Commercial	42%	43%	45%	47%
Industrial	21%	22%	21%	19%

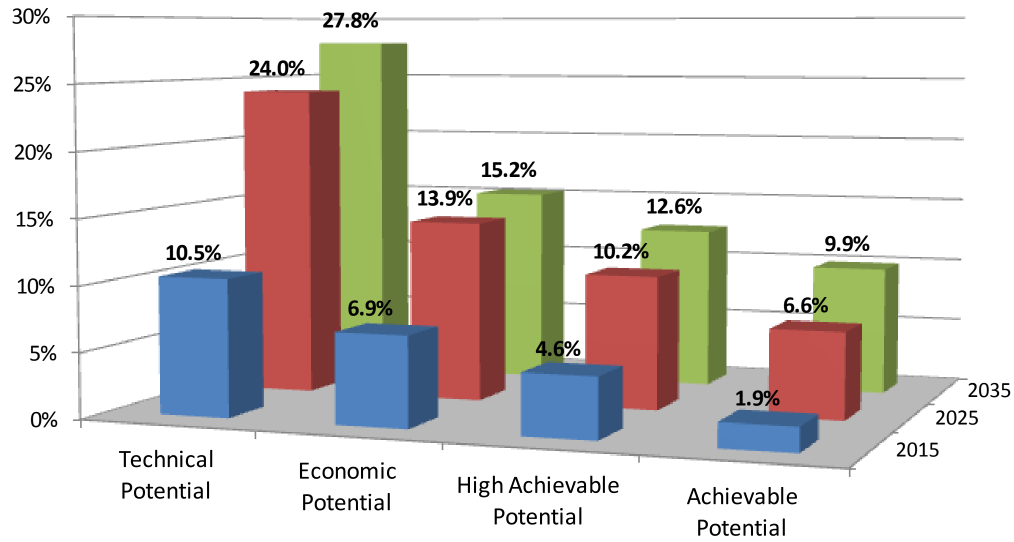

Figure D-2
Energy Efficiency Potential – West Census Region

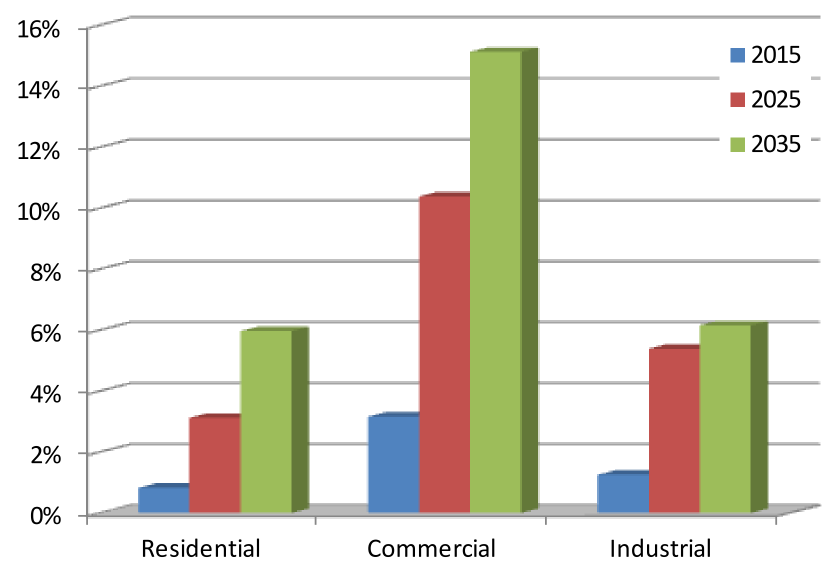

Figure D-3
Achievable Potential by Sector (as a Percentage of Sector Baseline) – West Census Region

Table D-2
Share of Achievable Potential by Sector and Division - West

	2015	2025	2035
West Total (GWh)	12,816	52,187	87,029
Residential	2%	3%	4%
Commercial	11%	12%	12%
Industrial	3%	4%	3%
Mountain North Total	17%	18%	19%
Residential	4%	4%	7%
Commercial	13%	14%	14%
Industrial	4%	5%	3%
Mountain South Total	21%	23%	24%
Residential	4%	4%	4%
Commercial	18%	16%	16%
Industrial	4%	4%	3%
Pacific Total	25%	24%	23%
Residential	6%	6%	7%
Commercial	25%	23%	23%
Industrial	5%	6%	4%
California Total	37%	35%	34%

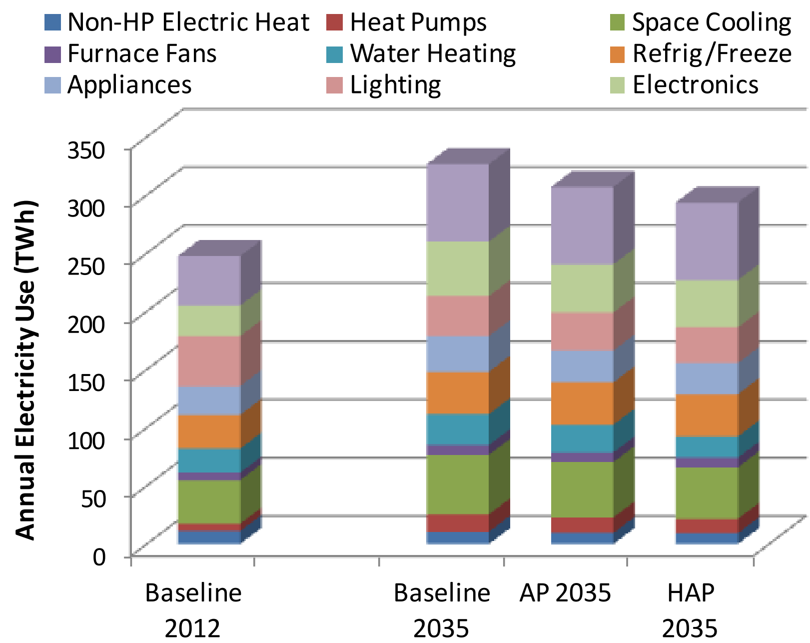

Figure D-4
Residential Baseline and Achievable Potential by End Use – West

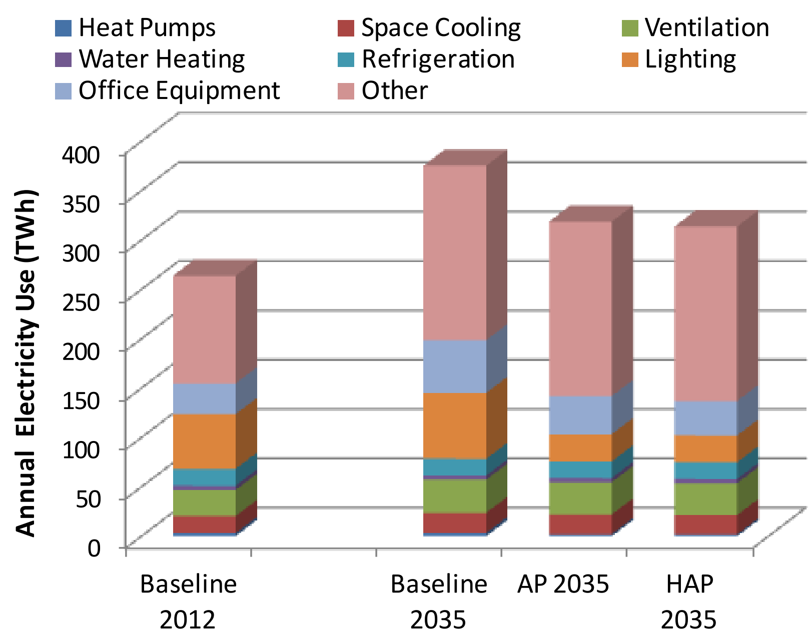

Figure D-5
Commercial Baseline and Achievable Potential by End Use - West

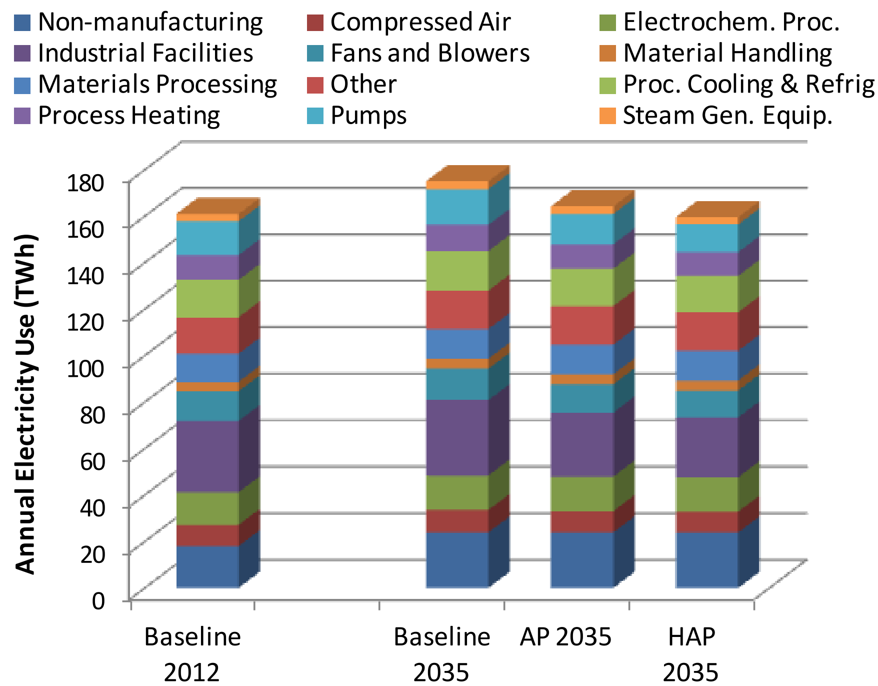

Figure D-6
Industrial Baseline and Achievable Potential by End Use - West

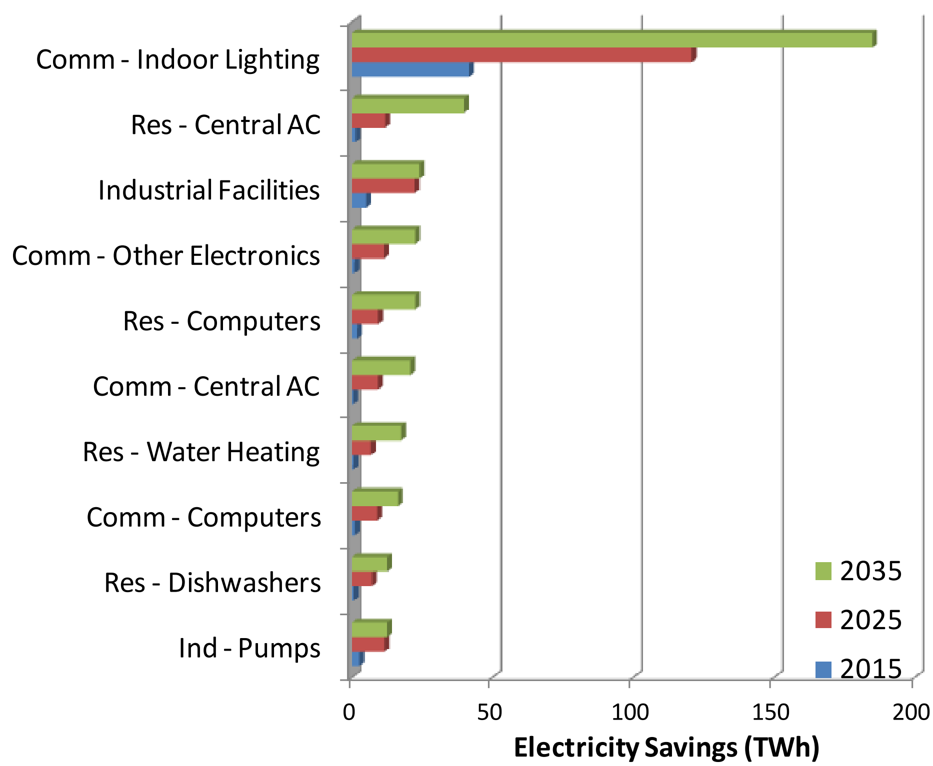

Figure D-7
Achievable Potential Top 10 End Uses – West Census Region

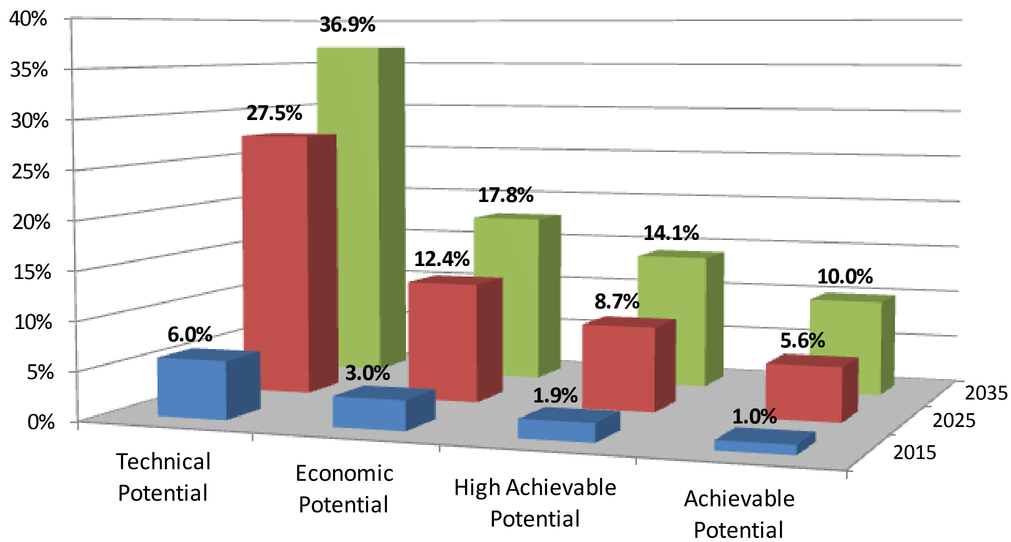

Figure D-8
Summer Peak Coincident Demand Potential – West Region

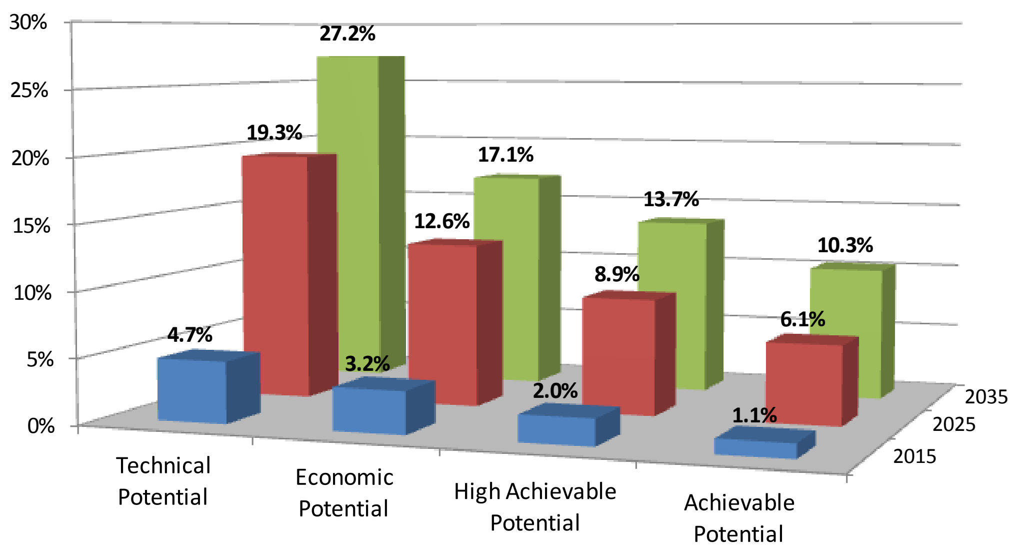

Figure D-9
Winter Peak Coincident Demand Potential – West Region

Appendix E: Residential Energy Efficiency Measure Data

Each residential end use has one or more measures that may be applied. For some measures there may be several technology choices. In this case all options have a benefit-cost ratio, and the winning measure is chosen as the measure with the highest energy savings with a benefit-cost ratio greater than or equal to 1.0. Each end use will have a primary measure associated with it; this is typically replacing the equipment providing the end use. An example is water heating where the primary measure is a water heater. There are also secondary measures which can provide water heating energy savings and often times these secondary measures have only two options, as a base they *are not* installed, and if they pass the economic screen they *are* installed.

To evaluate the technical potential we assume that the energy efficient measures are adopted regardless of their cost-effectiveness. For primary measures or measures with multiple technology options, the measure with the highest energy savings is used in the technical potential. For secondary measures with only one option (not installed/installed), the measures are installed.

The following data are associated with efficiency measures in the residential sector:

- Measure savings
  - Incremental **energy savings** relative to the base technology, as a percent of the base end-use unit energy consumption (UEC)
  - Incremental summer coincident demand savings relative to the base technology, as a percent of the base end-use summer demand
  - Incremental winter coincident demand **savings** relative to the base technology, as a percent of the base end-use winter demand
- Measure costs
  - **Base cost** of the technology, this is zero if the technology would not otherwise be installed
  - **Incremental cost** relative to the base technology
- Application factors adjust the energy savings, demand savings, and incremental and base cost of a secondary measure (e.g., building shell measures), these differ for new versus existing homes in the residential model

  - **Un-saturation** indicates the fraction of residential customers that do *not* have the measure installed
  - **Applicability** identifies the fraction of residential customers eligible for the measures (i.e., programmable thermostats are applicable to homes with central heating and/or cooling)
  - **Feasibility** identifies the fraction of units that can be replaced from an engineering perspective

- Market acceptance ratios (MARs) are applied to the economic potential to calculate the high achievable potential; The MARs reflect customers' resistance to doing more than the absolute minimum required or a dislike of the technology option
- Program implementation factors (PIFs) are applied to the high achievable potential to calculate the achievable potential; The PIF reflects existing market, financial, political, and regulatory barriers that are likely to limit the amount of savings achieved through EE programs

In addition to this measure level data, each end-use has an assumed average lifetime as shown in Table E-1. This lifetime is used in the stock turnover models to calculate the survival curve for the equipment. It is also used in the economic screen where the benefits and costs are calculated over the lifetime of the measures. In most cases the end-use lifetime is used for applied secondary measures. This average lifetime implies that some equipment in the stock turnover will need to be replaced before its average lifetime and some equipment will live beyond its average lifetime.

Table E-1
Residential Average Equipment Lifetimes

End Use	Average Life (years)
Room AC	12
Central AC	18
Heat Pump (replacing air-source heat pumps)	15
Heat Pump (replacing non-heat pump heating and central AC)	18
Ground-Source Heat Pump	18
Water Heater	15
Dishwasher	13
Clothes Washer	14
Clothes Dryer	18
Refrigerator	18
Freezer	18
Cooking	18
Television	11
Personal Computer	4
Smart Plug Strip (reduce standby wattage for TVs and PCs)	10
Furnace Fan	18
Enhanced Bill Presentment	4 year program
Indoor Screw-In Lighting	Each lamp operates 2.3 hours a day
Indoor Linear Fluorescent Lighting	Each lamp operates 4 hours a day

Residential Measure Savings and Costs

Details of efficient measure savings and costs are shown by end use in Table E-2 through Table E-12. Measure categories with several technology options will have indented options listed below the measure category, the technology options do not have separate base costs, application factors, MARs or PIFs, as these are applicable at the measure category level. Many secondary measures only have one technology choice and in that case the base technology choice is either not installing that technology or installing a standard version of that technology.

The measure impacts are the incremental savings in energy (UEC), summer coincident demand (SD), and winter coincident demand (WD) compared to the base choice. For primary measures and some secondary measures that have multiple technology options the base measure will have an incremental savings of 0% (relative to itself) and all other incremental savings are relative to the base measure. For measures with only one technology choice, the incremental savings is relative to either installing a standard version of the technology, or in many cases relative to not installing the measure.

The incremental cost of a technology is the cost relative to the base choice. For primary measures and some secondary measures the base measure will have an incremental cost of zero (relative to itself) and all other incremental costs are relative to the total cost of the base measure. For measures with only one technology choice, the incremental cost is relative to either installing a standard version of the technology, or in many cases relative to not installing the measure.

The base cost applies to the measure category and for measures with multiple technology choices the base measure will have a base cost listed while the incremental costs of other technology choices are relative to the base cost. For measures with only one technology choice the base cost is zero if the default option is not installing the measure and the incremental cost represents the total cost to install the measure; if there is a standard technology option, then there will be a base cost not equal to zero and the incremental cost of the technology is relative to the base cost.

Where efficiency standards come into effect in the next few years the initial base technology will be labeled and the new base technology will be identified along with the year that it comes into effect. Once the new standard comes into effect all incremental savings and costs are measured relative to that new base technology. In addition, within the model the UEC and demand for that end use are adjusted to reflect the savings from the standard.

Primary measures for weather-sensitive end uses have different measure savings by Census region as seen in Table E-2 through Table E-10.

Table E-2
Residential Measure Savings for Heat Pumps Replacing Non-Heat Pump Electric Heating and Central AC

Space Heating and Cooling	Northeast			South			Midwest			West		
	UEC	SD	WD	UEC	SD	WD	UEC	SD	WD	UEC	SD	WD
Primary Heating Equipment + Central AC	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HSPF=7.7; SEER=13	40%	0%	37%	20%	0%	48%	30%	0%	36%	26%	0%	48%
HSPF=8.1; SEER=14 (base >=2015)	47%	8%	50%	26%	8%	50%	45%	8%	50%	31%	8%	50%
HSPF=8.6; SEER=15	50%	14%	53%	31%	14%	53%	48%	14%	53%	36%	15%	53%
HSPF=9.0; SEER=16	52%	20%	55%	35%	20%	55%	51%	20%	55%	39%	20%	55%
HSPF=9.3; SEER=18	55%	29%	56%	41%	29%	56%	54%	29%	56%	44%	29%	56%
HSPF=10.0; SEER 20	58%	36%	59%	46%	36%	59%	57%	36%	59%	49%	36%	59%
HSPF=10.7; SEER 21	61%	39%	62%	49%	39%	62%	60%	39%	62%	52%	39%	62%
HSPF=11.3; SEER 22+	63%	42%	64%	51%	42%	64%	62%	42%	64%	54%	42%	64%
HSPF=12; SEER 25, DHP	69%	58%	75%	60%	59%	75%	69%	59%	75%	63%	58%	75%
COP=3; GSHP	72%	67%	75%	63%	76%	75%	72%	70%	75%	68%	69%	75%
Future Tech[34]	70%	87%	79%	70%	90%	68%	79%	90%	80%	73%	89%	68%
Attic Fans	0%	0%	0%	0%	0%	0%	0%	0%	0%	7%	7%	0%
Ceiling Fans	3%	0%	0%	0%	0%	0%	0%	0%	0%	13%	9%	0%
Whole House Fans	4%	0%	0%	1%	0%	0%	0%	0%	0%	16%	9%	0%
Duct Insulation	5%	4%	4%	3%	4%	4%	4%	3%	3%	5%	4%	4%

Note: UEC = unit energy consumption in kWh/unit/year; SD = summer coincident demand in kW/unit; WD = winter coincident demand in kW/unit; HSPF = heating seasonal performance factor; SEER = seasonal energy efficiency ratio; DHP = ductless heat pump; COP = coefficient of performance; GSHP = ground-source heat pump;

[34] The future technology is applied beginning in 2020 and therefore the savings and costs are relative to the 2020 baseline technology, in this case a heat pump with HSPF of 8.1 and SEER 14.

Table E-2 (continued)
Residential Measure Savings for Heat Pumps Replacing Non-Heat Pump Electric Heating and Central AC

Space Heating and Cooling	Northeast			South			Midwest			West		
	UEC	SD	WD	UEC	SD	WD	UEC	SD	WD	UEC	SD	WD
Programmable Thermostat	9%	6%	4%	11%	1%	5%	9%	6%	6%	11%	7%	8%
Storm Doors	1%	2%	2%	1%	1%	1%	1%	2%	2%	1%	2%	2%
External Shades	3%	12%	0%	5%	9%	0%	2%	9%	0%	8%	10%	0%
Ceiling Insulation - R-30	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
R-38	0%	0%	0%	2%	1%	2%	0%	0%	0%	3%	0%	0%
R-50	3%	2%	2%	5%	1%	2%	4%	2%	1%	6%	2%	2%
Foundation Insulation	4%	0%	0%	1%	0%	0%	4%	2%	2%	3%	2%	2%
Wall Insulation - R-13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
R-19	0%	2%	2%	0%	1%	1%	0%	2%	2%	0%	0%	0%
R-30	1%	2%	2%	1%	3%	3%	1%	2%	2%	1%	2%	2%
R-38	1%	4%	4%	1%	4%	4%	1%	3%	3%	1%	2%	2%
Reflective Roof	4%	23%	0%	9%	21%	0%	3%	18%	0%	9%	19%	0%
Windows - Base	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Double Pane	23%	13%	13%	18%	13%	13%	18%	10%	10%	18%	13%	13%
ENERGY STAR	34%	19%	19%	27%	20%	20%	27%	16%	16%	25%	18%	18%
HP Maintenance	9%	10%	8%	10%	10%	10%	9%	9%	9%	10%	9%	9%
Duct Repair	24%	16%	16%	20%	24%	24%	25%	21%	21%	21%	13%	13%
Infiltration Control	5%	0%	0%	4%	1%	1%	5%	3%	3%	2%	2%	2%
Dehumidification	0%	1%	0%	0%	1%	0%	0%	1%	0%	0%	1%	0%

Note: UEC = unit energy consumption in kWh/unit/year; SD = summer coincident demand in kW/unit; WD = winter coincident demand in kW/unit

Table E-3
Residential Heat Pump Measure Costs (Replacing Non-Heat Pump Electric Heat and Central AC Cooling)

Space Heating and Cooling	Northeast		South		Midwest		West	
	Inc.	Base	Inc.	Base	Inc.	Base	Inc.	Base
Primary Heating Equipment + Central AC	$0.00	$9,353	$0.00	$8,430	$0.00	$8,514	$0.00	$7,881
HSPF=7.7; SEER=13	-$3,853		-$2,930		-$3,014		-$2,381	
HSPF=8.1; SEER=14 (base >=2015)	-$3,453		-$2,530		-$2,614		-$1,981	
HSPF=8.6; SEER=15	-$3,053		-$2,130		-$2,214		-$1,581	
HSPF=9.0; SEER=16	-$2,653		-$1,730		-$1,814		-$1,181	
HSPF=9.3; SEER=18	-$1,853		-$930		-$1,014		-$381	
HSPF=10.0; SEER 20	-$1,353		-$430		-$514		$119	
HSPF=10.7; SEER 21	-$853		$70		-$14		$619	
HSPF=11.3;SEER 22+	$147		$1,070		$986		$1,619	
HSPF=12;SEER 25, DHP	$647		$1,570		$1,486		$2,119	
COP=3; GSHP	$1,647		$2,570		$2,486		$3,119	
Future Tech[35]	$1,975		$3,058		$3,040		$3,806	
Attic Fans	$398	$312	$398	$312	$398	$312	$398	$312
Ceiling Fans	$497	$258	$497	$258	$497	$258	$497	$258
Whole House Fans	$250	$391	$250	$391	$250	$391	$250	$391
Duct Insulation	$40	$0	$40	$0	$40	$0	$40	$0

Note: Residential costs are shown in $ per unit. HSPF = heating seasonal performance factor; SEER = seasonal energy efficiency ratio; COP = coefficient of performance; HP = heat pump; GSHP = ground-source heat pump

[35] The future technology is applied beginning in 2020 and therefore the savings and costs are relative to the 2020 baseline technology, in this case a heat pump with HSPF of 8.1 and SEER 14.

Table E-3 (continued)
Residential Heat Pump Measure Costs (Replacing Non-Heat Pump Electric Heat and Central AC Cooling)

Space Heating and Cooling	Northeast		South		Midwest		West	
	Inc.	Base	Inc.	Base	Inc.	Base	Inc.	Base
Programmable Thermostat	$91	$35	$91	$35	$91	$35	$91	$35
Storm Doors	$28	$204	$28	$204	$28	$204	$28	$204
External Shades	$367	$1,350	$367	$1,350	$367	$1,350	$367	$1,350
Ceiling Insulation R-30	$0	$3,349	$0	$2,979	$0	$3,349	$0	$2,979
R-38	$0		$370		$0		$370	
R-50	$1,369		$1,739		$1,369		$1,739	
Foundation Insulation	$167	$0	$167	$0	$167	$0	$167	$0
Wall Insulation R-13	$0	$1,789	$0	$1,789	$0	$1,789	$0	$1,789
R-19	$2,110		$2,110		$2,110		$2,110	
R-30	$5,947		$5,947		$5,947		$5,947	
R-38	$8,735		$8,735		$8,735		$8,735	
Reflective Roof	$498	$0	$498	$0	$498	$0	$498	$0
Windows - Base	$0	$2,040	$0	$2,040	$0	$2,040	$0	$2,040
Double Pane	$378		$378		$378		$378	
ENERGY STAR	$931		$931		$931		$931	
HP Maintenance	$490	$0	$490	$0	$490	$0	$490	$0
Duct Repair	$532	$0	$532	$0	$532	$0	$532	$0
Infiltration Control	$91	$0	$91	$0	$91	$0	$91	$0
Dehumidification	$16	$199	$16	$199	$16	$199	$16	$199

Note: Residential costs are shown in $ per unit.

Table E-4
Residential Measure Savings for Heat Pumps Replacing Air-Source Heat Pumps (Heating and Cooling)

Heat Pumps Space Heating and Cooling	Northeast			South			Midwest			West		
	UEC	SD	WD	UEC	SD	WD	UEC	SD	WD	UEC	SD	WD
HP - SEER 13 (initial base)	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SEER 14 (base >=2015)	5%	8%	3%	7%	8%	4%	4%	8%	3%	6%	8%	4%
SEER 15	10%	14%	6%	12%	14%	9%	8%	14%	6%	11%	15%	9%
SEER 16	14%	20%	9%	17%	20%	13%	12%	20%	9%	16%	20%	13%
SEER 18	18%	29%	12%	23%	29%	16%	15%	29%	11%	21%	29%	16%
SEER 20	24%	36%	16%	30%	36%	21%	20%	36%	15%	27%	36%	21%
SEER 21	29%	39%	20%	34%	39%	26%	24%	39%	19%	31%	39%	27%
SEER 22+, Ducted Variable Speed	32%	42%	23%	37%	42%	30%	27%	42%	22%	35%	42%	30%
SEER 25, DHP	43%	58%	56%	48%	59%	51%	44%	59%	54%	47%	58%	50%
SEER 25, GSHP	45%	67%	63%	52%	76%	52%	48%	70%	63%	57%	69%	52%
Future Tech[36]	55%	83%	81%	63%	90%	65%	60%	88%	81%	70%	86%	65%
Attic Fans	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	7%	0%
Ceiling Fans	4%	0%	0%	0%	0%	0%	0%	0%	0%	10%	9%	0%
Whole House Fans	4%	0%	0%	1%	0%	0%	0%	0%	0%	12%	9%	0%
Duct Insulation	2%	4%	4%	3%	4%	4%	2%	3%	3%	4%	4%	4%
Programmable Thermostat	12%	6%	4%	6%	1%	5%	9%	6%	6%	11%	7%	8%
Storm Doors	1%	2%	2%	1%	1%	1%	0%	2%	2%	1%	2%	2%

Note: UEC = unit energy consumption in kWh/unit/year; SD = summer coincident demand in kW/unit; WD = winter coincident demand in kW/unit; HSPF = heating seasonal performance factor; SEER = seasonal energy efficiency ratio; DHP = ductless heat pump; COP = coefficient of performance; GSHP = ground-source heat pump;

[36] The future technology is applied beginning in 2020, the savings and costs are relative to the SEER 14 the 2020 baseline technology.

Table E-4 (continued)
Residential Measure Savings for Heat Pumps Replacing Air-Source Heat Pumps (Heating and Cooling)

Heat Pumps Space Heating and Cooling	Northeast			South			Midwest			West		
	UEC	SD	WD	UEC	SD	WD	UEC	SD	WD	UEC	SD	WD
External Shades	3%	12%	0%	5%	9%	0%	2%	9%	0%	6%	10%	0%
Ceiling Insulation - R-30	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
R-38	0%	0%	0%	2%	1%	2%	0%	0%	0%	4%	0%	0%
R-50	4%	2%	2%	4%	1%	2%	6%	2%	1%	7%	2%	2%
Foundation Insulation	1%	0%	0%	1%	0%	0%	1%	2%	2%	1%	2%	2%
Wall Insulation - R-13	0%	0%	0%	0.0%	0%	0%	0.0%	0%	0%	0.0%	0%	0%
R-19	0.2%	2%	2%	0.2%	1%	1%	0.2%	2%	2%	0.2%	0%	0%
R-30	0.3%	2%	2%	0.3%	3%	3%	0.4%	2%	2%	0.3%	2%	2%
R-38	0.4%	4%	4%	0.4%	4%	4%	0.4%	3%	3%	0.3%	2%	2%
Reflective Roof	5%	23%	0%	8%	21%	0%	3%	18%	0%	7%	19%	0%
Windows - Base	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Double Pane	14%	13%	13%	8%	13%	13%	9%	10%	10%	13%	13%	13%
ENERGY STAR	17%	19%	19%	12%	20%	20%	12%	16%	16%	17%	18%	18%
HP Maintenance	10%	10%	8%	10%	10%	10%	10%	9%	9%	10%	9%	9%
Duct Repair	15%	16%	16%	19%	24%	24%	17%	21%	21%	11%	13%	13%
Infiltration Control	1%	0%	0%	2%	1%	1%	2%	3%	3%	0%	2%	2%
Dehumidification	0%	1%	0%	0%	1%	0%	0%	1%	0%	0%	1%	0%

Note: UEC = unit energy consumption in kWh/unit/year; SD = summer coincident demand in kW/unit; WD = winter coincident demand in kW/unit

Table E-5
Residential Heat Pump Measure Costs (Replacing Air-Source Heat Pumps for Heating and Cooling)

Measure	Cost		Measure	Cost	
	Inc.	Base		Inc.	Base
HP - SEER 13 (initial base)	$0	$4,500	Ceiling Insulation R-30	$0	$3,349/ $2,979
SEER 14 (base >=2015)	$400		R-38	$0/ $370	
SEER 15	$800		R-50	$1,369/ $1,739	
SEER 16	$1,200		Programmable Thermostat	$41	$16
SEER 18	$2,000		Foundation Insulation	$167	$0
SEER 20	$2,800		Wall Insulation R-13	$0	$1,789
SEER 21	$3,200		R-19	$2,110	
SEER 22+, Ducted Variable Speed	$3,600		R-30	$5,947	
SEER 25, DHP	$4,000		R-38	$8,735	
SEER 25, GSHP	$6,000		Reflective Roof	$498	$0
Future Tech[37]	$6,375		Windows - Base	$0	$2,040
Attic Fans	$312	$398	Double Pane	$378	
Ceiling Fans	$258	$497	ENERGY STAR	$931	
Whole House Fans	$391	$250	HP Maintenance	$490	$0
Duct Insulation	$18	$0	Duct Repair	$532	$0
Storm Doors	$13	$92	Infiltration Control	$91	$0
External Shades	$367	$1,350	Dehumidification	$16	$199

Note: Residential costs are shown in $ per unit. Cost data for Ceiling Insulation is listed for the Northeast and Midwest/South and West Census regions. HP = heat pump; HSPF = heating seasonal performance factor; SEER = seasonal energy efficiency ratio; DHP = ductless heat pump; GSHP = ground-source heat pump

[37] The future technology is applied beginning in 2020, the savings and costs are relative to the SEER 14 the 2020 baseline technology.

Table E-6
Residential Central AC Space Cooling Measures

Central AC Space Cooling	Northeast		South		Midwest		West		Cost	
	UEC	SD	UEC	SD	UEC	SD	UEC	SD	Inc.	Base
Central AC - SEER 13 (initial base)	0%	0%	0%	0%	0%	0%	0%	0%	$0.00	$4,500
SEER 14 (base >=2015)	8%	8%	8%	8%	8%	8%	8%	8%	$400	
SEER 15	14%	14%	14%	14%	14%	14%	14%	15%	$800	
SEER 16	20%	20%	20%	20%	20%	20%	20%	20%	$1,200	
SEER 18	29%	29%	29%	29%	29%	29%	29%	29%	$2,000	
SEER 20	36%	36%	36%	36%	36%	36%	36%	36%	$2,500	
SEER 21	39%	39%	39%	39%	39%	39%	39%	39%	$3,000	
SEER 22+, Ducted Variable Speed	42%	42%	42%	42%	42%	42%	42%	42%	$4,000	
SEER 25, DHP	51%	58%	52%	59%	53%	59%	53%	58%	$4,500	
SEER 25, GSHP	59%	67%	55%	76%	61%	70%	61%	69%	$6,500	
Future Tech[38]	72%	83%	67%	90%	67%	88%	67%	86%	$7,625	
Attic fans	0%	0%	0%	0%	0%	0%	14%	7%	$311.54	$398.00
Ceiling Fans	16%	0%	1%	0%	0%	0%	26%	9%	$258.29	$497.00
Whole House Fans	20%	0%	1%	0%	0%	0%	31%	9%	$391.35	$250.00
Duct Insulation	2%	4%	3%	4%	2%	3%	4%	4%	$18.17	$0.00
Programmable Thermostat	12%	6%	6%	1%	9%	6%	11%	7%	$40.95	$15.75
Storm Doors	1%	2%	1%	1%	0%	2%	1%	2%	$12.55	$91.80

Note: There are no winter peak demand savings for space cooling, only summer demand savings are shown. Residential costs are shown in $ per unit. UEC = unit energy consumption in kWh/unit/year; SD = summer coincident demand in kW/unit; AC = air conditioning; SEER = seasonal energy efficiency ratio; DHP = ductless heat pump; GSHP = ground-source heat pump

[38] The future technology is applied beginning in 2020, the savings and costs are relative to the SEER 14 the 2020 baseline technology.

Table E-6 (continued)
Residential Central AC Space Cooling Measures

Central AC Space Cooling	Northeast		South		Midwest		West		Cost	
	UEC	SD	UEC	SD	UEC	SD	UEC	SD	Inc.	Base
External Shades	14%	12%	8%	9%	10%	9%	16%	10%	$367	$1,350
Ceiling Insulation - R-30	0%	0%	0%	0%	0%	0%	0%	0%	$0	$1506/ $1,340
R-38	0%	0%	2%	1%	0%	0%	4%	0%	$0/ $167	
R-50	4%	2%	4%	1%	6%	2%	7%	2%	$616/ $783	
Foundation Insulation	1%	0%	1%	0%	1%	2%	1%	2%	$75	$0
Wall Insulation - R-13	0%	0%	0.0%	0%	0.0%	0%	0.0%	0%	$0	$805
R-19	0.2%	2%	0.2%	1%	0.2%	2%	0.2%	0%	$950	
R-30	0.3%	2%	0.3%	3%	0.4%	2%	0.3%	2%	$2,676	
R-38	0.4%	4%	0.4%	4%	0.4%	3%	0.3%	2%	$3,931	
Reflective Roof	21%	23%	15%	21%	14%	18%	18%	19%	$498	$0
Windows - Base	0%	0%	0%	0%	0%	0%	0%	0%	$0	$918
Double Pane	14%	13%	8%	13%	9%	10%	13%	13%	$170	
ENERGY STAR	17%	19%	12%	20%	12%	16%	17%	18%	$419	
AC Maintenance	10%	10%	10%	10%	10%	9%	10%	9%	$335	$0
Duct Repair	15%	16%	19%	24%	17%	21%	11%	13%	$239	$0
Infiltration Control	1%	0%	2%	1%	2%	3%	0%	2%	$41	$0
Dehumidifier	1%	1%	1%	1%	1%	1%	1%	1%	$16	$199

Note: There are no winter peak demand savings for space cooling, only summer demand savings are shown. Residential costs are shown in $ per unit. Cost data for Ceiling Insulation is listed for the Northeast and Midwest/South and West Census regions. UEC = unit energy consumption in kWh/unit/year; SD = summer coincident demand in kW/unit; AC = air conditioning

Table E-7
Residential Ground-Source Heat Pump Measure Savings (Heating and Cooling)

Ground-Source Heat Pumps Heating and Cooling	Northeast			South			Midwest			West		
	UEC	SD	WD	UEC	SD	WD	UEC	SD	WD	UEC	SD	WD
GSHP – Standard	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Efficient	28%	34%	8%	28%	34%	8%	28%	34%	8%	28%	34%	8%
Max Efficiency	49%	92%	28%	49%	92%	28%	49%	92%	28%	49%	92%	28%
Future Tech[39]	63%	90%	36%	63%	90%	36%	63%	90%	36%	63%	90%	36%
Attic Fans	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	7%	0%
Ceiling Fans	4%	0%	0%	0%	0%	0%	0%	0%	0%	10%	9%	0%
Whole House Fans	4%	0%	0%	1%	0%	0%	0%	0%	0%	12%	9%	0%
Duct Insulation	2%	4%	4%	3%	4%	4%	2%	3%	3%	4%	4%	4%
Programmable Thermostat	12%	6%	4%	6%	1%	5%	9%	6%	6%	11%	7%	8%
Storm Doors	1%	2%	2%	1%	1%	1%	0%	2%	2%	1%	2%	2%
External Shades	3%	12%	0%	5%	9%	0%	2%	9%	0%	6%	10%	0%
Ceiling Insulation - R-30	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
R-38	0%	0%	0%	2%	1%	2%	0%	0%	0%	4%	0%	0%
R-50	4%	2%	2%	4%	1%	2%	6%	2%	1%	7%	2%	2%
Foundation Insulation	1%	0%	0%	1%	0%	0%	1%	2%	2%	1%	2%	2%
Wall Insulation - R-13	0%	0%	0%	0.0%	0%	0%	0.0%	0%	0%	0.0%	0%	0%
R-19	0.2%	2%	2%	0.2%	1%	1%	0.2%	2%	2%	0.2%	0%	0%
R-30	0.3%	2%	2%	0.3%	3%	3%	0.4%	2%	2%	0.3%	2%	2%
R-38	0.4%	4%	4%	0.4%	4%	4%	0.4%	3%	3%	0.3%	2%	2%

Note: UEC = unit energy consumption in kWh/unit/year; SD = summer coincident demand in kW/unit; WD = winter coincident demand in kW/unit; GSHP = ground-source heat pump

[39] The future technology is applied beginning in 2020, the savings and costs are relative to Standard, the 2020 baseline technology.

Table E-7 (continued)
Residential Ground-Source Heat Pump Measure Savings (Heating and Cooling)

Ground-Source Heat Pumps Heating and Cooling	Northeast			South			Midwest			West		
	UEC	SD	WD	UEC	SD	WD	UEC	SD	WD	UEC	SD	WD
Reflective Roof	5%	23%	0%	8%	21%	0%	0%	0%	0%	7%	19%	0%
Windows - Base	0%	0%	0%	0%	0%	0%	9%	10%	0%	0%	0%	0%
Double Pane	14%	13%	13%	8%	13%	13%	12%	16%	10%	13%	13%	13%
ENERGY STAR	17%	19%	19%	12%	20%	20%	10%	9%	16%	17%	18%	18%
HP Maintenance	10%	10%	8%	10%	10%	10%	17%	21%	9%	10%	9%	9%
Duct Repair	15%	16%	16%	19%	24%	24%	2%	3%	21%	11%	13%	13%
Infiltration Control	1%	0%	0%	2%	1%	1%	0%	1%	3%	0%	2%	2%
Dehumidification	0%	1%	0%	0%	1%	0%	0%	0%	0%	0%	1%	0%

Note: UEC = unit energy consumption in kWh/unit/year; SD = summer coincident demand in kW/unit; WD = winter coincident demand in kW/unit; HP = heat pump

Table E-8
Residential Ground-Source Heat Pump Measure Costs (Heating and Cooling)

Measure	Cost		Measure	Cost	
	Inc.	Base		Inc.	Base
GSHP – Standard	$0	$11,000	Ceiling Insulation R-30	$0	$3,349/$2,979
Efficient	$1,000		R-38	$0/ $370	
Max Efficiency	$2,500		R-50	$1,369/ $1,739	
Future Tech[40]	$3,125		Programmable Thermostat	$91	$35
Attic Fans	$398	$312	Foundation Insulation	$166.84	$0
Ceiling Fans	$497	$258	Reflective Roof	$498.49	$0
Whole House Fans	$250	$391	Windows - Base	$0.00	$2,040
Duct Insulation	$40	$0	Double Pane	$378.08	
Storm Doors	$28	$204	ENERGY STAR	$931.16	
External Shades	$367	$1,350	HP Maintenance	$490.30	$0
Wall Insulation R-13	$0	$1,789	Duct Repair	$532.04	$0
R-19	$2,110		Infiltration Control	$90.75	$0
R-30	$5,947		Dehumidification	$16	$199
R-38	$8,735				

Note: Residential costs are shown in $ per unit. Cost data for Ceiling Insulation is listed for the Northeast and Midwest/South and West Census regions. GSHP = ground-source heat pump; HP = heat pump

[40] The future technology is applied beginning in 2020, the savings and costs are relative to Standard, the 2020 baseline technology.

Table E-9
Residential Room AC Measures

Room AC	Northeast		South		Midwest		West		Cost	
	UEC	SD	UEC	SD	UEC	SD	UEC	SD	Inc.	Base
EER 9.8 (initial base)	0%	0%	0%	0%	0%	0%	0%	0%	$0	$235
EER 10.2	4%	4%	4%	4%	4%	4%	4%	4%	$14	
EER 10.8	9%	9%	9%	9%	9%	9%	9%	9%	$37	
EER 11 (base >=2014)	11%	11%	11%	11%	11%	11%	11%	11%	$47	
EER 11.5	15%	15%	15%	15%	15%	15%	15%	15%	$67	
EER > 11.5	20%	20%	20%	20%	20%	20%	20%	20%	$100	
Future Tech[41]	21%	21%	20%	20%	20%	20%	21%	21%	$66	

Note: There are no winter peak demand savings for space cooling, only summer demand savings are shown. Residential costs are shown in $ per unit. UEC = unit energy consumption in kWh/unit/year; SD = summer coincident demand in kW/unit; WD = winter coincident demand in kW/unit; EER = energy efficiency ratio

[41] The future technology is applied beginning in 2020, the savings and costs are relative to EER 11, the 2020 baseline technology.

Table E-10
Residential Water Heating Measures

Water Heating	Northeast			South			Midwest			West			Cost	
	UEC	SD	WD	UEC	SD	WD	UEC	SD	WD	UEC	SD	WD	Inc.	Base
Water Heater EF = 0.90 (Base <2015)	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	$0	$500
EF = 0.95 (Base>=2015)	8%	5%	3%	9%	6%	4%	8%	5%	3%	8%	5%	4%	$194	
HP EF = 2	50%	57%	21%	55%	62%	35%	45%	64%	23%	55%	59%	38%	$1,203	
Solar	66%	69%	46%	69%	94%	17%	62%	88%	8%	59%	87%	9%	$4,300	
HP EF=3	75%	75%	58%	70%	72%	55%	64%	73%	47%	70%	70%	57%	$2,500	
GSHP EF=4	78%	78%	61%	78%	77%	65%	73%	78%	59%	78%	76%	67%	$4,500	
Future Tech[42]	80%	81%	62%	80%	81%	62%	80%	81%	62%	80%	81%	62%	$5,383	
Dishwasher - Base	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	$0	$0
Efficient	3%	1%	1%	3%	1%	1%	3%	1%	1%	3%	1%	1%	$60	
ENERGY STAR	4%	1%	1%	4%	1%	1%	4%	1%	1%	4%	1%	1%	$89	
Advanced Technology	5%	2%	2%	5%	2%	2%	5%	2%	2%	5%	2%	2%	$334	
Faucet Aerators	3%	0%	0%	3%	0%	0%	3%	0%	0%	3%	0%	0%	$1	$0
Pipe Insulation	6%	0%	0%	6%	0%	0%	6%	0%	0%	6%	0%	0%	$15	$0
Low-Flow Showerheads	15%	0%	0%	15%	0%	0%	15%	0%	0%	15%	0%	0%	$3	$0

Note: Residential costs are shown in $ per unit. Beginning in 2013 dishwashers must be 14% more efficient than the current standard. UEC = unit energy consumption in kWh/unit/year; SD/WD = summer/winter coincident demand in kW/unit; EF = energy factor; HP = heat pump

[42] The future technology is applied beginning in 2020, the savings and costs are relative to EF=0.95, the 2020 baseline technology.

Table E-11
Residential Appliances Measures

Appliances	Impacts			Cost	
	UEC	Summer Demand	Winter Demand	Incre-mental	Base
Refrigerators - Base (initial)	0%	0%	0%	$0	$788
Efficient (base>=2014)	20%	20%	20%	$212	
High-Efficiency	25%	25%	25%	$437	
Maximum Efficiency (available 2012)	35%	35%	35%	$812	
Future Tech[43]	40%	40%	40%	$2,775	
Cooking - Base	0%	0%	0%	$0	$500
Efficient	20%	5%	5%	$124	
Clothes Dryers - Base (standard change in 2014)	0%	0%	0%	$0	$439
Moisture Sensor	10%	1%	1%	$111	
High-Efficiency	15%	2%	2%	$256	
Heat Pump	50%	5%	5%	$1,291	
Combination Washer/Dryer	55%	6%	6%	$1,800	
Freezers - Base	0%	0%	0%	$0	$508
ENERGY STAR	10%	10%	10%	$27	
Efficient	25%	25%	25%	$242	
High-Efficiency	30%	30%	30%	$3,192	
Future Tech[43]	13%	13%	13%	$3,688	
Clothes Washers - Base (initial)	0%	0%	0%	$0	$500
MEF=1.72 (base>=2015)	27%	3%	3%	$600	
MEF=2.0 (base>=2018)	37%	4%	4%	$650	
MEF=2.4	48%	5%	5%	$700	
MEF=2.8	55%	6%	6%	$800	

Note: Beginning in 2014 Clothes Dryers must be 5% more efficient than the current standard. Beginning in 2014 Freezers must be 25% more efficient than the current standard. Residential costs are shown in $ per unit. UEC = unit energy consumption in kWh/unit/year; MEF = modified energy factor

[43] The future technology is applied beginning in 2020, the savings and costs are relative to the 2020 baseline technology.

Table E-11 (continued)
Residential Appliances Measures

Appliances	Impacts			Cost	
	UEC	Summer Demand	Winter Demand	Incre-mental	Base
Dishwashers – Base (initial)	0%	0%	0%	$0	$345
Efficient	25%	10%	10%	$8	
ENERGY STAR	35%	15%	15%	$12	
Advanced Technology	50%	20%	20%	$46	
Furnace Fans – ECM	40%	0%	0%	$101	$75

Note: Beginning in 2013 dishwashers must be 14% more efficient than the current standard. Residential costs are shown in $ per unit. Beginning UEC = unit energy consumption in kWh/unit/year; ECM = electronically commutated motor

Table E-12
Residential Television and Personal Computer Measures

	Impacts			Cost	
	UEC	Summer Demand	Winter Demand	Incre-mental	Base
Television - Standard	0%	0%	0%	$0	$399
ENERGY STAR	30%	15%	15%	$88	
Advanced Technology	60%	25%	25%	$457	
Reduce Standby Wattage (TVs)	5%	2%	2%	$10	$0
Personal Computer - Standard	0%	0%	0%	$0	$499
ENERGY STAR	30%	15%	15%	$18	
Advanced Technology	65%	33%	33%	$140	
Reduce Standby Wattage (PCs)	5%	2%	2%	$10	$0

Note: Residential costs are shown in $ per unit. UEC = unit energy consumption in kWh/unit/year

Enhanced bill presentment is treated uniquely. The measure may provide energy and demand savings at the whole-house level and as such the economic screen is performed based on average annual household consumption and coincident demand. The savings potential is not calculated using a stock turnover, instead it is assumed that a service provider could offer the measure to their entire residential customer base and roll out to 100% of customers. Since these savings cannot be attributed to a single end use they are presented as a separate category in the potential results. The measure data is shown in Table E-13.

Table E-13
Residential Whole House Measure

	Impacts			Cost	
	UEC	Summer Demand	Winter Demand	Incre-mental	Base
Enhanced Customer Bill Presentment	2%	1%	1%	$160	$0

Note: Residential costs are shown in $ per unit. UEC = unit energy consumption in kWh/unit/year

Indoor lighting is split into three segments in the residential sector, screw-in lighting, linear fluorescent, and other lighting. The other lighting category is comprised of miscellaneous technologies that do not fall into the standard screw-in or linear fluorescent categories; no measures are applied to other lighting. Table E-14 has screw-in measures which are compared to a hybrid baseline technology which is comprised of incandescents and CFLs in the beginning of the forecast. As the EISA standards for lighting come into effect first in 2014 (for 60 W lamps) and then in 2020 any incandescent stock is modeled in the first round as the EISA-compliant New Halogen, in Tier 2 any remaining incandescent stock is modeled as the EISA Tier 2 technology in Table E-14.. Depending on the user inputs for CFL saturation the hybrid base technology will change over time as the technology in the incandescent portion of the screw-in stock changes.

Note that the dimmable technologies are assumed to be operating at 80% of their full output on average. Therefore their lumen output is somewhat lower than typical screw-in replacement technologies. When lighting technologies go through the economic screen their watts/lamp and cost are adjusted to reflect the technology's lumen output compared to the hybrid baseline technology. If a technology has a lower lumen output than the hybrid baseline technology the watts/lamp and cost are adjusted upward to get an equivalent lumen output. In this way we are replacing the turned over stock with an equivalent amount of light. There is no lumen adjustment for dimmable technologies as the savings from these technologies are due to a lower level of output light (20% dimmed). The LED lamps are also not lumen adjusted since the technologies are considered to provide equivalent light on working surfaces even though the lumen output may be lower. The lighting future technology is assumed to have 110 lumens/watt of output light.

Table E-14
Residential Indoor Screw-In Lighting Measures

	Watts	Lumens	Lamp Cost	Dimmer Cost	Life (hours)
Incandescent	60	800	$0.25	N/A	1,000
New Halogen (EISA Tier 1, 2014)	43	850	$1.50	N/A	1,500
EISA Tier 2 (2020)	18	800	$1.50	N/A	1,500
CFL (60W equivalent)	13	800	$3.00	N/A	5,000
LED	12	850	$25 ($10 after 2015)	N/A	25,000
CFL w/ Integrated Dimmer	11	660	$8.00	N/A	5,000
CFL (dimmable)	12	660	$5.00	$30	4,500
LED (dimmable)	8	680	$55 ($40 after 2015)	$30	25,000
Super Incandescent	28	850	$2.00	N/A	1,500
Future Technology	7.3	800	$50.00	N/A	25,000

Note: EISA = Energy Independence and Security Act of 2007; CFL = compact fluorescent lamp; LED = light emitting diode

Table E-15 has linear fluorescent lighting technologies which are compared to a hybrid baseline technology comprised of T12s and T8s. Depending on the user input shares of linear fluorescent stock the characteristics of the hybrid technology will vary.

Note that the dimmable technologies are assumed to be operating at 80% of their full output on average. Therefore their lumen output is somewhat lower than typical linear fluorescent replacement technologies. When lighting technologies go through the economic screen their watts/lamp and costs are adjusted to reflect the technology's lumen output compared to the hybrid baseline technology. If a technology has a lower lumen output than the hybrid baseline technology the watts/lamp and costs are adjusted upward to get an equivalent lumen output. In this way we are replacing the turned over stock with an equivalent amount of light. There is no lumen adjustment for dimmable technologies as the savings from these technologies is due to a lower level of output light (20% dimmed). The LED technologies are also not lumen adjusted since the technologies are considered to provide equivalent light on working surfaces even though the lumen output may be lower.

It is assumed that all technologies have four lamps per fixture with the exception of two lamps per fixture for the T5 high output and induction technologies, and a single unit replacement for the LED fixture and future technology which are integrated units (including the lighting technology and ballast in the fixture).

The lighting future technology is assumed to have 110 lumens/watt of output light.

Table E-15
Residential Indoor Linear Fluorescent Lighting Measures

	Watts /Lamp	Lumens /Lamp	Fixture Cost	Ballast Cost	Lamp Cost	Life (hours)
T12	40	2,650	$19.00	$19.40	$1.65	20,000
T8	32	2,950	$19.00	$18.00	$2.00	20,000
T5	27	2,900	$68.00	$28.00	$2.00	20,000
T5 High Output	54	5,000	$99.00	$28.00	$6.50	20,000
Super T8	32	3,100	$19.00	$18.00	$3.00	20,000
T8 Dimmable	26	2,360	$19.00	$40.00	$2.00	20,000
T5 Dimmable	22	2,320	$68.00	$40.00	$2.00	20,000
Linear LED	22	2,110	-	-	$65.0	40,000
LED Fixture	60	5,145	$500.00	-	-	70,000

Note: Watts and lumens data are per lamp. The linear LED technology is a tube replacement where existing T12 and T8 lamps are replaced one-for-one with LED tube lamps. LED = light emitting diode

Residential Application Factors

The application factors apply to secondary measures; when a measure passes the economic screen the energy and demand savings, incremental cost, and base cost are scaled using the application factors for inclusion in end-use impacts and costs. The un-saturation, applicability and feasibility do not apply to primary measures instead these factors are captured in the end-use saturation. Note that the un-saturation is the percent of customers that do not currently have this measure installed. I.e., if a measure has 40% un-saturation then 40% of customers do *not* have the measure present. Residential measure application factors are shown in Table E-16. These measures are different for new versus existing homes in the residential sector.

Table E-16
Residential Application Factors

Measure		Northeast			South			Midwest			West		
		Un-Sat	Appl	Feas	Un-Sat	Appl	Feas	Un-Sat	Appl	Feas	Un-Sat	Appl	Feas
Attic Fans	New	96%	76%	29%	96%	75%	100%	96%	88%	21%	96%	94%	9%
	Ex.	97%	28%	29%	97%	59%	100%	97%	70%	21%	97%	52%	9%
Ceiling Fans	New	52%	76%	100%	23%	75%	100%	27%	88%	100%	49%	94%	100%
	Ex.	52%	28%	100%	23%	59%	100%	27%	70%	100%	49%	52%	100%
Whole House Fans	New	96%	76%	29%	96%	75%	100%	96%	88%	21%	96%	94%	9%
	Ex.	97%	28%	29%	97%	59%	100%	97%	70%	21%	97%	52%	9%
Duct Insulation	New	86%	95%	100%	93%	100%	100%	90%	88%	100%	84%	76%	100%
	Ex.	50%	35%	100%	50%	78%	100%	50%	70%	100%	50%	42%	100%
Programmable Thermostat	New	75%	76%	100%	82%	100%	100%	71%	88%	100%	74%	76%	100%
	Ex.	75%	28%	100%	82%	78%	100%	71%	70%	100%	74%	42%	100%
Storm Doors	New	50%	95%	100%	50%	100%	100%	50%	88%	100%	50%	57%	100%
	Ex.	50%	35%	100%	50%	78%	100%	50%	70%	100%	50%	31%	100%
External Shades	New	90%	76%	100%	90%	100%	100%	90%	88%	100%	90%	94%	100%
	Ex.	90%	4%	100%	90%	12%	100%	90%	11%	100%	90%	8%	100%
Ceiling Insulation	New	86%	95%	100%	93%	100%	100%	90%	88%	100%	84%	76%	100%
	Ex.	86%	5%	100%	93%	12%	100%	90%	11%	100%	84%	6%	100%
Foundation Insulation	New	86%	95%	100%	93%	100%	100%	90%	88%	100%	84%	76%	100%
	Ex.	86%	5%	100%	93%	12%	100%	90%	11%	100%	84%	6%	100%
Wall Insulation	New	86%	95%	100%	93%	100%	100%	90%	88%	100%	84%	76%	100%
	Ex.	86%	5%	100%	93%	12%	100%	90%	11%	100%	84%	6%	100%

Table E-16 (continued)
Residential Application Factors

Measure		Northeast			South			Midwest			West		
		Un-Sat	Appl	Feas	Un-Sat	Appl	Feas	Un-Sat	Appl	Feas	Un-Sat	Appl	Feas
Reflective Roof	New	90%	76%	100%	90%	100%	100%	90%	88%	100%	90%	94%	100%
	Ex.	90%	4%	100%	90%	12%	100%	90%	11%	100%	90%	8%	100%
Windows	New	6%	76%	100%	6%	100%	100%	6%	88%	100%	6%	94%	100%
	Ex.	6%	4%	100%	6%	12%	100%	6%	11%	100%	6%	8%	100%
HP Maint.(NHP el. heat + CAC, GSHPs)	Ex.	50%	2%	100%	50%	21%	100%	50%	2%	100%	50%	4%	100%
HP Maint. (ASHPs)	Ex.	50%	26%	100%	50%	57%	100%	50%	68%	100%	50%	35%	100%
AC Maint. (central AC)	Ex.	50%	26%	100%	50%	57%	100%	50%	68%	100%	50%	35%	100%
Duct Repair	Ex.	50%	28%	100%	50%	78%	100%	50%	70%	100%	50%	42%	100%
Infiltration Control	New	86%	76%	100%	93%	100%	100%	90%	88%	100%	84%	76%	100%
	Ex.	50%	28%	100%	50%	78%	100%	50%	70%	100%	50%	42%	100%
Dehumidifier	New	82%	76%	100%	95%	100%	100%	75%	88%	100%	99%	57%	100%
	Ex.	82%	28%	100%	95%	78%	100%	75%	70%	100%	99%	31%	100%
Faucet Aerators	New	85%	25%	100%	62%	62%	100%	86%	23%	100%	94%	10%	100%
	Ex.	85%	23%	100%	62%	58%	100%	86%	21%	100%	90%	15%	100%
Pipe Insulation	New	82%	25%	100%	55%	62%	100%	84%	23%	100%	93%	10%	100%
	Ex.	90%	23%	100%	74%	58%	100%	91%	21%	100%	93%	15%	100%

Table E-16 (continued)
Residential Application Factors

Measure		Northeast			South			Midwest			West		
		Un-Sat	Appl	Feas	Un-Sat	Appl	Feas	Un-Sat	Appl	Feas	Un-Sat	Appl	Feas
Low-Flow Showerheads	New	81%	25%	100%	52%	62%	100%	82%	23%	100%	92%	10%	100%
	Ex.	81%	23%	100%	52%	58%	100%	82%	21%	100%	88%	15%	100%
Reduce Standby Wattage (TVs and PCs)	New	99%	76%	100%	99%	100%	100%	99%	88%	100%	99%	76%	100%
	Ex.	99%	28%	100%	99%	78%	100%	99%	70%	100%	99%	42%	100%

Note: HP Maintenance is applied for homes with non-heat pump electric heating and central AC cooling (NHP electric heat + CAC), homes with ground-source heat pumps (GSHP) and homes with air-source heat pumps (ASHP). HP Maint. For ASHPs has different factors. HP = heat pump; AC = air conditioning.

Residential MARs and PIFs

The market acceptance ratios (MARs) and program implementation factors (PIFs) apply at the measure level. For measures with multiple technology choices the same MARs and PIFs are applied regardless of the winning technology. They are specified for 2010, 2020, and 2030 and are interpolated/extrapolated for other years, with a minimum of 0% and maximum of 100%.

The MARs are used to scale the economic potential energy and demand impacts, and costs for the winning measures to find the high achievable potential. This is done at the measure level and summed to the end-use level for use in the stock turnover.

The PIFs are used to scale the high achievable potential energy and demand impacts, and costs for the winning measures to find the achievable potential. This is also done at the measure level and summed to the end-use level for use in the stock turnover. The residential MARs and PIFs are shown in Table E-17 and Table E-18 respectively. Primary measures in weather-sensitive end uses may have different MARs and PIFs by Census region.

Table E-17
Residential Market Acceptance Ratios (MARs)

Measure	Northeast			South			Midwest			West		
	2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030
Heat Pumps (Non-HP+CAC)	25%	38%	50%	25%	38%	50%	25%	38%	50%	25%	38%	50%
Heat Pumps(ASHP)	50%	75%	100%	50%	75%	100%	50%	75%	100%	50%	75%	100%
Ground-Source Heat Pumps	5%	13%	20%	5%	13%	20%	5%	13%	20%	5%	13%	20%
Central AC	50%	75%	100%	50%	75%	100%	50%	75%	100%	50%	75%	100%
Attic Fans	25%	75%	75%	25%	75%	75%	25%	75%	75%	25%	75%	75%
Ceiling Fans	26%	79%	80%	25%	76%	76%	25%	76%	76%	26%	77%	77%
Whole House Fans	26%	79%	80%	25%	76%	76%	25%	76%	76%	26%	77%	77%
Duct Insulation	26%	53%	80%	25%	51%	76%	25%	51%	76%	26%	51%	77%
Programmable Thermostat	35%	79%	100%	34%	76%	100%	33%	76%	100%	34%	77%	100%
Storm Doors	26%	53%	80%	25%	51%	76%	25%	51%	76%	26%	51%	77%
External Shades	26%	53%	80%	25%	51%	76%	25%	51%	76%	26%	51%	77%
Ceiling Insulation	35%	74%	95%	34%	71%	91%	33%	71%	91%	34%	71%	92%
Foundation Insulation	35%	74%	95%	34%	71%	91%	33%	71%	91%	34%	71%	92%
Wall Insulation	35%	74%	95%	34%	71%	91%	33%	71%	91%	34%	71%	92%
Reflective Roof	35%	74%	95%	34%	71%	91%	33%	71%	91%	34%	71%	92%
Windows	26%	53%	80%	25%	51%	76%	25%	51%	76%	26%	51%	77%
HP and AC Maintenance	26%	53%	80%	25%	51%	76%	25%	51%	76%	26%	51%	77%
Duct Repair	26%	53%	80%	25%	51%	76%	25%	51%	76%	26%	51%	77%

Note: Non-HP+CAC is for heat pumps replacing both non-heat pump electric heating and central AC cooling. ASHP is for heat pumps replacing existing air-source heat pumps.

Table E-17 (continued)
Residential Market Acceptance Ratios (MARs)

Measure	Northeast			South			Midwest			West		
	2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030
Infiltration Control	26%	53%	80%	25%	51%	76%	25%	51%	76%	26%	51%	77%
Dehumidifier	26%	79%	80%	25%	76%	76%	25%	76%	76%	26%	77%	77%
Room AC	53%	95%	95%	51%	91%	91%	51%	91%	91%	51%	92%	92%
Water Heater <= 55 gallons	5%	40%	75%	5%	40%	75%	5%	40%	75%	5%	40%	75%
Water Heater > 55 gallons	10%	50%	90%	10%	50%	90%	10%	50%	90%	10%	50%	90%
Dishwashers (domestic hot water)	53%	95%	95%	51%	91%	91%	51%	91%	91%	51%	92%	92%
Faucet Aerators	53%	79%	80%	51%	76%	76%	51%	76%	76%	51%	77%	77%
Pipe Insulation	53%	79%	80%	51%	76%	76%	51%	76%	76%	51%	77%	77%
Low-Flow Showerheads	53%	79%	80%	51%	76%	76%	51%	76%	76%	51%	77%	77%
Refrigerators	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Cooking	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Clothes Dryers	53%	95%	95%	51%	91%	91%	51%	91%	91%	51%	92%	92%
Freezers	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Screw-In Lighting	75%	83%	90%	75%	83%	90%	75%	83%	90%	75%	83%	90%
Linear Fluorescent Lighting	10%	53%	95%	10%	53%	95%	10%	53%	95%	10%	53%	95%
Clothes Washers	53%	95%	95%	51%	91%	91%	51%	91%	91%	51%	92%	92%
Dishwashers	53%	95%	95%	51%	91%	91%	51%	91%	91%	51%	92%	92%

Note: AC = air conditioning; DHW = domestic hot water

Table E-17 (continued)
Residential Market Acceptance Ratios (MARs)

Measure	Northeast			South			Midwest			West		
	2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030
Televisions	53%	79%	80%	51%	76%	76%	51%	76%	76%	51%	77%	77%
Personal Computers	53%	79%	80%	51%	76%	76%	51%	76%	76%	51%	77%	77%
Reduce Standby Wattage (TVs and PCs)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Furnace Fans	26%	79%	80%	25%	76%	76%	25%	76%	76%	26%	77%	77%
Enhanced Billing	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%

Table E-18
Residential Program Implementation Factors (PIFs)

Measure	Northeast			South			Midwest			West		
	2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030
Heat Pumps (Non-HP+CAC)	40%	70%	100%	40%	70%	100%	40%	70%	100%	40%	70%	100%
Heat Pumps(ASHP)	50%	75%	100%	50%	75%	100%	50%	75%	100%	50%	75%	100%
Ground-Source Heat Pumps	20%	23%	25%	20%	23%	25%	20%	23%	25%	20%	23%	25%
Central AC	50%	75%	100%	50%	75%	100%	50%	75%	100%	50%	75%	100%
Attic Fans	10%	25%	40%	10%	25%	40%	10%	25%	40%	10%	25%	40%
Ceiling Fans	8%	24%	40%	5%	23%	40%	7%	23%	40%	10%	25%	40%
Whole House Fans	16%	33%	50%	10%	30%	50%	13%	31%	50%	20%	35%	50%

Note: Non-HP+CAC is for heat pumps replacing both non-heat pump electric heating and central AC cooling. ASHP is for heat pumps replacing existing air-source heat pumps.

Table E-18 (continued)
Residential Program Implementation Factors (PIFs)

Measure	Northeast			South			Midwest			West		
	2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030
Duct Insulation	4%	17%	30%	3%	16%	30%	3%	17%	30%	5%	18%	30%
Programmable Thermostat	16%	45%	75%	10%	42%	75%	13%	44%	75%	20%	48%	75%
Storm Doors	4%	15%	25%	3%	14%	25%	3%	14%	25%	5%	15%	25%
External Shades	4%	17%	30%	3%	16%	30%	3%	17%	30%	5%	18%	30%
Ceiling Insulation	4%	17%	30%	3%	16%	30%	3%	17%	30%	5%	18%	30%
Foundation Insulation	4%	17%	30%	3%	16%	30%	3%	17%	30%	5%	18%	30%
Wall Insulation	4%	17%	30%	3%	16%	30%	3%	17%	30%	5%	18%	30%
Reflective Roof	8%	29%	50%	5%	27%	50%	7%	28%	50%	10%	30%	50%
Windows	12%	36%	60%	8%	34%	60%	10%	35%	60%	15%	38%	60%
HP and AC Maintenance	4%	12%	20%	3%	11%	20%	3%	12%	20%	5%	13%	20%
Duct Repair	4%	17%	30%	3%	16%	30%	3%	17%	30%	5%	18%	30%
Infiltration Control	4%	17%	30%	3%	16%	30%	3%	17%	30%	5%	18%	30%
Dehumidifier	1%	3%	5%	1%	3%	5%	1%	3%	5%	1%	3%	5%
Room AC	40%	65%	90%	25%	58%	90%	33%	61%	90%	50%	70%	90%
Water Heater <= 55 gallons	20%	27%	33%	20%	27%	33%	20%	27%	33%	20%	27%	33%
Water Heater > 55 gallons	33%	45%	56%	33%	45%	56%	33%	45%	56%	33%	45%	56%

Note: AC = air conditioning; DHW = domestic hot water

Table E-18 (continued)
Residential Program Implementation Factors (PIFs)

Measure	Northeast			South			Midwest			West		
	2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030
Dishwashers(DHW)	40%	65%	90%	25%	58%	90%	33%	61%	90%	50%	70%	90%
Faucet Aerators	4%	17%	30%	3%	16%	30%	3%	17%	30%	5%	18%	30%
Pipe Insulation	4%	17%	30%	3%	16%	30%	3%	17%	30%	5%	18%	30%
Low-Flow Showerheads	4%	17%	30%	3%	16%	30%	3%	17%	30%	5%	18%	30%
Refrigerators	40%	65%	90%	25%	58%	90%	33%	61%	90%	50%	70%	90%
Cooking	16%	31%	45%	10%	27%	45%	13%	29%	45%	20%	32%	45%
Clothes Dryers	24%	37%	50%	15%	33%	50%	20%	35%	50%	30%	40%	50%
Freezers	24%	42%	60%	15%	38%	60%	20%	40%	60%	30%	45%	60%
Screw-In Lighting	33%	50%	67%	33%	50%	67%	33%	50%	67%	33%	50%	67%
Linear Fluorescent Lighting	50%	75%	100%	50%	75%	100%	50%	75%	100%	50%	75%	100%
Clothes Washers	40%	65%	90%	25%	58%	90%	33%	61%	90%	50%	70%	90%
Dishwashers	40%	65%	90%	25%	58%	90%	33%	61%	90%	50%	70%	90%
Televisions	20%	45%	70%	13%	41%	70%	16%	43%	70%	25%	48%	70%
Personal Computers	20%	50%	80%	13%	46%	80%	16%	48%	80%	25%	52%	80%
Reduce Standby (TVs and PCs)	12%	38%	65%	8%	36%	65%	10%	37%	65%	15%	40%	65%
Furnace Fans	20%	35%	50%	13%	31%	50%	16%	33%	50%	25%	38%	50%
Enhanced Billing	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%

Appendix F: Commercial Energy Efficiency Measure Data

Each commercial end use has one or more measures that may be applied. For some measures there may be several technology choices in a category. In this case all options have a benefit-cost ratio, the winning measure is chosen as the measure with the highest energy savings and a benefit-cost ratio greater than or equal to 1.0. Each end use will have a primary measure associated with it, this is typically a choice in replacing the equipment providing the end use. An example is space heating where the primary measure is a heat pump. There are also secondary measures which can provide space heating energy savings and often times these secondary measures have two options, as a base they *are not* installed, and if they pass the economic screen they *are* installed.

To evaluate the technical potential we assume that all measures are adopted regardless of their cost-effectiveness. For primary measures or measures with multiple technology options, the measure with the highest energy savings is used in the technical potential. For secondary measures with only one option (not installed/installed), the measures are installed.

The following data are associated with efficiency measures in the commercial sector:

- Measure savings
  - Incremental energy savings relative to the base technology, as a percent of the base end-use energy use intensity (EUI)
  - Incremental summer coincident demand savings relative to the base technology, as a percent of the base end-use summer demand
  - Incremental winter coincident demand savings relative to the base technology, as a percent of the base end-use winter demand
- Measure costs
  - **Base cost** of the technology, in some cases this is zero if the technology would not otherwise be installed
  - **Incremental cost** relative to the base technology
- Application factors adjust the energy savings, demand savings, and incremental and base cost of a secondary measure (e.g., building shell measures)

- **Un-saturation** indicates the fraction of commercial floor space that *does not* have the measure installed
- **Applicability** identifies the fraction of commercial floor space eligible for the measures (i.e., programmable thermostats are applicable to buildings with central heating and/or cooling)
- **Feasibility** identifies the fraction of units that can be replaced from an engineering perspective

- Market acceptance ratios (MARs) are applied to the economic potential to calculate the high achievable potential; The MARs reflect customers' resistance to doing more than the absolute minimum required or a dislike of the technology option
- Program implementation factors (PIFs) are applied to the high achievable potential to calculate the achievable potential; The PIF reflects existing market, financial, political, and regulatory barriers that are likely to limit the amount of savings achieved through EE and DR programs

In addition to this measure level data, each end-use has an assumed average lifetime as shown in Table F-1. This lifetime is used in the stock turnover models to calculate the survival curve for the equipment. It is also used in the economic screen where the benefits and costs are calculated over the lifetime of the end use. In most cases the end-use lifetime is used for applied secondary measures. This average lifetime implies that some equipment in the stock turnover will need to be replaced before its average lifetime and some equipment will live beyond its average lifetime.

Table F-1
Commercial Average Equipment Lifetimes

End Use	Average Lifetime (years)
Heat Pump	15
Central AC	15
Chiller	19
Water Heater	15
Refrigeration	15
Personal Computers	5
Copiers Printers	8
Other Electronics	8
Servers	5
Monitors	8
Indoor Screw-In Lighting	Each lamp operates 4 hours a day
Indoor Linear Fluorescent Lighting	Each lamp operates 12 hours a day

Commercial Measure Savings and Costs

Details of efficient measure savings and costs are shown by end use in Table F-2 through Table F-8. Measure categories with several technology options will have indented options listed below the measure category, the technology options do not have separate base costs, application factors, MARs or PIFs, as these are applicable at the measure category level. Secondary measures only have one technology choice and in that case the base technology choice is either not installing that technology or installing a standard version of that technology.

The measure impacts are the incremental savings in energy (EUI), summer coincident demand (SD), and winter coincident demand (WD) compared to the base choice. For primary measures and some secondary measures that have multiple technology options the base measure will have an incremental savings of 0% (relative to itself) and all other incremental savings are relative to the base measure. For measures with only one technology choice, the incremental savings is relative to either installing a standard version of the technology, or in many cases relative to not installing the measure.

The incremental cost of a technology is the cost relative to the base choice. For primary measures and some secondary measures the base measure will have an incremental cost of zero (relative to itself) and all other incremental costs are relative to the total cost of the base measure. For measures with only one technology choice, the incremental cost is relative to either installing a standard version of the technology, or in many cases relative to not installing the measure.

The base cost applies to the measure category and for measures with multiple technology choices the base measure will have a base cost listed while the incremental costs of other technology choices are relative to the base cost. For measures with only one technology choice the base cost is zero if the default option is not installing the measure and the incremental cost represents the total cost to install the measure; if there is a standard technology option, then there will be a base cost not equal to zero and the incremental cost of the technology is relative to the base cost.

Where efficiency standards come into effect in the next few years the initial base technology will be labeled and the new base will be identified along with the year that it comes into effect. Once the new standard comes into effect all incremental savings and costs are measured relative to that new base technology.

Primary measures for weather-sensitive end uses have different measure savings by Census region as seen in Table F-2 through Table F-6.

Table F-2
Commercial Measure Savings for Heat Pumps Replacing Heat Pump Heating and Cooling

Space Heating	Northeast			South			Midwest			West			Cost	
	EUI	SD	WD	EUI	SD	WD	EUI	SD	WD	EUI	SD	WD	Inc.	Base
Heat Pump - COP = 3.3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	$0.00	$0.02
COP = 3.4	10%	4%	5%	9%	7%	1%	13%	4%	9%	14%	0%	14%	$0.08	
COP = 4.0	26%	10%	14%	24%	17%	2%	27%	9%	16%	29%	0%	29%	$0.33	
COP = 5.0	38%	18%	16%	43%	31%	4%	46%	17%	25%	40%	0%	40%	$0.78	
COP = 5.7	47%	23%	24%	39%	33%	6%	58%	27%	30%	50%	0%	50%	$0.99	
Future Tech[44]	65%	32%	33%	54%	47%	8%	80%	38%	42%	70%	0%	70%	$1.24	
Economizer	9%	0%	0%	6%	0%	0%	7%	0%	0%	0%	0%	0%	$0.42	$0.10
Duct Insulation	2%	1%	1%	1%	1%	0%	2%	1%	1%	2%	0%	2%	$0.14	$0.00
EMS	14%	8%	4%	16%	12%	1%	13%	7%	3%	6%	0%	6%	$0.41	$0.00
Programmable Thermostat	14%	0%	0%	10%	0%	0%	15%	0%	0%	20%	0%	0%	$0.25	$0.01
Duct Testing and Sealing	4%	3%	4%	7%	5%	7%	4%	3%	4%	8%	6%	8%	$0.14	$0.00
Cool Roof	1%	1%	0%	2%	1%	0%	1%	1%	0%	2%	2%	0%	$0.11	$2.63
Roof Insulation	2%	1%	2%	2%	1%	0%	2%	1%	2%	3%	0%	3%	$0.10	$0.00
Efficient Windows	8%	2%	5%	6%	3%	1%	8%	2%	5%	10%	0%	10%	$0.26	$0.14
HVAC Retro.	10%	4%	5%	10%	7%	1%	10%	4%	5%	10%	0%	10%	$0.77	$0.00

Note: Although a heat pump efficiency standard requiring a minimum COP of 3.3 does not come into effect until 2012, the COP 3.3 unit is used as the base technology in 2010 and 2011 also. Commercial costs are shown in $/sqft. EUI = energy use intensity in kWh/sqft; SD/WD = summer/winter coincident demand in kW/sqft; WD = winter coincident demand in kW/sqft; COP = coefficient of performance; EMS = energy management system; HVAC = heating, ventilation, and air conditioning; HVAC Retro. = HVAC retrocommissioning

[44] The future technology is applied beginning in 2020, the savings and costs are relative to the 2020 baseline technology.

Table F-3
Commercial Central AC Space Cooling Measures

Central AC Space Cooling	Northeast		South		Midwest		West		Cost	
	EUI	SD	EUI	SD	EUI	SD	EUI	SD	Inc.	Base
Central AC - EER = 11.0	0%	0%	0%	0%	0%	0%	0%	0%	$0.00	$0.48
EER = 12.0	10%	8%	10%	8%	10%	8%	10%	8%	$0.13	
EER = 14.0	25%	20%	25%	20%	25%	20%	25%	20%	$0.42	
VRF, EER = 18.0	45%	36%	45%	36%	45%	36%	45%	36%	$0.88	
Future Tech[45]	63%	50%	63%	50%	63%	50%	63%	50%	$1.10	
Economizer	18%	0%	7%	0%	15%	0%	19%	0%	$0.19	$0.05
Duct Insulation	2%	2%	1%	2%	2%	2%	2%	2%	$0.07	$0.00
Programmable Thermostat	8%	0%	9%	0%	10%	0%	6%	0%	$0.11	$0.00
Duct Testing and Sealing	8%	6%	8%	6%	8%	6%	8%	6%	$0.14	$0.00
Cool Roof	2%	2%	2%	2%	2%	2%	2%	2%	$0.11	$2.63
Roof Insulation	2%	1%	2%	1%	2%	1%	2%	1%	$0.04	$0.00
Efficient Windows	5%	4%	5%	4%	5%	4%	5%	4%	$0.11	$0.06

Note: There are no winter peak demand savings for space cooling, only summer demand savings are shown. Commercial costs are shown in $/sqft. EUI = energy use intensity in kWh/sqft; SD = summer coincident demand in kW/sqft; WD = winter coincident demand in kW/sqft; AC = air conditioning; EER = energy efficiency ratio; VRF = variable refrigerant flow

[45] The future technology is applied beginning in 2020, the savings and costs are relative to the 2020 baseline technology.

Table F-4
Commercial Chiller Space Cooling Measures

Chiller Space Cooling	Northeast		South		Midwest		West		Cost	
	EUI	SD	EUI	SD	EUI	SD	EUI	SD	Inc.	Base
Chiller - 1.41 kW/ton	0%	0%	0%	0%	0%	0%	0%	0%	$0.00	$0.22
1.30 kW/ton	8%	6%	8%	6%	8%	6%	8%	6%	$0.13	
1.23 kW/ton	13%	10%	13%	10%	13%	10%	13%	10%	$0.28	
1.11 kW/ton	21%	17%	21%	17%	21%	17%	21%	17%	$0.77	
VRF	40%	32%	40%	32%	40%	32%	40%	32%	$3.91	
Future Tech[46]	56%	45%	56%	45%	56%	45%	56%	45%	$4.88	
VSD on Pump	5%	2%	2%	1%	3%	1%	6%	2%	$0.14	$0.02
EMS	21%	17%	17%	14%	20%	16%	31%	25%	$0.18	$0.00
Variable Air Volume System	34%	18%	31%	11%	33%	13%	26%	7%	$0.43	$0.00
HVAC Retrocommissioning	10%	8%	10%	8%	10%	0%	10%	8%	$0.00	$0.00

Note: There are no winter peak demand savings for space cooling, only summer demand savings are shown. Commercial costs are shown in $/sqft. EUI = energy use intensity in kWh/sqft; SD = summer coincident demand in kW/sqft; WD = winter coincident demand in kW/sqft; VRF = variable refrigerant flow; VSD = variable speed drive; EMS = energy management system; HVAC = heating, ventilation, and air conditioning

[46] The future technology is applied beginning in 2020, the savings and costs are relative to the 2020 baseline technology.

Table F-5
Commercial Water Heating Measures

Water Heating	Northeast			South			Midwest			West			Cost	
	EUI	SD	WD	EUI	SD	WD	EUI	SD	WD	EUI	SD	WD	Inc.	Base
Water Heater - EF = 0.90 (Base <2015)	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	$0.00	$0.03
EF = 0.95	7%	3%	4%	3%	1%	2%	6%	2%	3%	2%	1%	1%	$0.01	
HP EF = 2.00 (Base >=2015)	20%	8%	12%	23%	9%	14%	19%	8%	11%	47%	19%	28%	$0.08	
HP EF = 3.00	33%	13%	20%	33%	13%	20%	33%	13%	20%	68%	27%	41%	$0.17	
CO_2 Heat Pump EF=4	47%	19%	28%	47%	19%	28%	39%	16%	24%	71%	28%	43%	$0.30	
Future Tech[47]	30%	9%	15%	30%	9%	15%	38%	13%	21%	69%	18%	31%	$0.31	
Water Temperature Reset	15%	6%	9%	11%	4%	6%	14%	5%	8%	24%	10%	15%	$0.11	$0.00

Note: Commercial costs are shown in $/sqft. EUI = energy use intensity in kWh/sqft; SD = summer coincident demand in kW/sqft; WD = winter coincident demand in kW/sqft; EF = energy factor

Table F-6
Commercial Ventilation Measures

Fans	Northeast			South			Midwest			West			Cost	
	EUI	SD	WD	EUI	SD	WD	EUI	SD	WD	EUI	SD	WD	Inc.	Base
Energy-Efficient Motors	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	$0.00	$0.01
Variable Speed Fan Control	26%	18%	18%	28%	12%	12%	26%	13%	13%	24%	8%	8%	$0.17	$0.01

Note: Commercial costs are shown in $/sqft. EUI = energy use intensity in kWh/sqft; SD = summer coincident demand in kW/sqft; WD = winter coincident demand in kW/sqft

[47] The future technology is applied beginning in 2020, the savings and costs are relative to EF=2.0, the 2020 baseline technology.

Table F-7
Commercial Refrigeration Measures

Refrigeration	Impacts			Cost	
	EUI	Summer Demand	Winter Demand	Inc.	Base
High-Efficiency Compressor	8%	6%	8%	$0.28	$0.03
Anti-Sweat Heater Controls	6%	6%	6%	$0.79	$0.00
Floating Head Pressure Controls	10%	10%	10%	$0.17	$0.00
Installation of Glass Doors	5%	4%	5%	$2.61	$0.00
High-Efficiency Vending Machine	4%	3%	4%	20%	$0.03
Icemakers	10%	8%	10%	$1.31	$0.03
Reach-in Coolers and Freezers	15%	12%	15%	$0.53	$0.03

Note: Commercial costs are shown in $/sqft. In 2012 vending machines must be 50% more efficient than current units, therefore no savings are available from High-Efficiency Vending Machines beginning in 2012. EUI = energy use intensity in kWh/sqft

Table F-8
Commercial Office Equipment Measures

Office Equipment	Impacts			Cost	
	EUI	Summer Demand	Winter Demand	Inc.	Base
Personal Computers - Base	0%	0%	0%	$0.00	$0.21
ENERGY STAR Base	30%	23%	23%	$0.01	
ENERGY STAR Efficient	45%	34%	34%	$0.06	
ENERGY STAR High Efficiency	65%	49%	49%	$0.23	
Servers - Base	0%	0%	0%	$0.00	$0.07
ENERGY STAR	30%	30%	30%	$0.00	
High Efficiency	40%	40%	40%	$0.11	
Monitors - Base	0%	0%	0%	$0.00	$0.02
ENERGY STAR Tier 1	20%	15%	15%	$0.02	
ENERGY STAR Tier 2	25%	19%	19%	$0.20	
Copiers & Printers - Base	0%	0%	0%	$0.00	$0.21
ENERGY STAR	40%	30%	30%	$0.03	
High Efficiency	50%	38%	38%	$0.28	
Other Electronics - Base	0%	0%	0%	$0.00	$0.20
ENERGY STAR	55%	41%	41%	$0.04	
High Efficiency	65%	49%	49%	$0.30	

Note: Commercial costs are shown in $/sqft. EUI = energy use intensity in kWh/sqft

Indoor lighting is split into three segments in the commercial sector, screw-in lighting, linear fluorescent lighting, and HID. HID lighting has no measures applied and is set aside in the potential calculation. Table F-9 has screw-in measures which are compared to a hybrid baseline technology which is comprised of incandescents and CFLs in the beginning of the forecast. As the EISA standards for lighting come into effect first in 2013 (for 75W lamps) and then in 2020 any incandescent stock is modeled in the first round as the EISA-compliant New Halogen, in Tier 2 any remaining incandescent stock is modeled as the EISA Tier 2 technology in Table F-9. Depending on the user inputs for CFL saturation the hybrid base technology will change over time as the technology in the incandescent portion of the screw-in stock changes.

Note that the dimmable technologies are assumed to be operating at 80% of their full output on average. Therefore their lumen output is somewhat lower than typical screw-in replacement technologies. When lighting technologies go through the economic screen their watts/lamp and cost are adjusted to reflect the technology's lumen output compared to the hybrid baseline technology. If a technology has a lower lumen output than the hybrid baseline technology the watts/lamp and cost are adjusted upward to get an equivalent lumen output. In this way we are replacing the turned over stock with an equivalent amount of light. There is no lumen adjustment for dimmable technologies as the savings from these technologies is due to a lower level of output light (20% dimmed). The LED lamps are also not lumen adjusted since the technologies are considered to provide equivalent light on working surfaces even though the lumen output may be lower. The lighting future technology is assumed to have 110 lumens/watt of output light.

Table F-9
Commercial Indoor Screw-In Lighting Measures

	Watts	Lumens	Lamp Cost	Dimmer Cost	Life (hours)
Incandescent	75	1,100	$0.25	N/A	1,000
New Halogen (EISA Tier 1, 2013)	52	1,100	$1.50	N/A	1,500
EISA Tier 2 (2020)	25	1,100	$1.50	N/A	1,500
CFL (75W equivalent)	17	1,050	$4.00	N/A	5,000
LED	17	1,100	$40 ($15 after 2015)	N/A	25,000
CFL with Integrated Dimmer	14.4	840	$8.00	N/A	5,000
CFL (dimmable)	16	840	$6.00	$30	4,500
LED (dimmable)	13.6	880	$70 ($45 after 2015)	$30	25,000
Super Incandescent	38	1,100	$2.00	N/A	1,500
Future Technology	10	1,100	$50.00	N/A	25,000

Note: EISA = Energy Independence and Security Act of 2007; CFL = compact fluorescent lamp; LED = light emitting diode

Table F-10 has linear fluorescent lighting technologies which are compared to a hybrid baseline technology comprised of T12s and T8s. Depending on the user input shares of linear fluorescent stock the characteristics of the hybrid technology will vary.

Note that the dimmable technologies are assumed to be operating at 80% of their full output on average. Therefore their lumen output is somewhat lower than typical linear fluorescent replacement technologies. When lighting technologies go through the economic screen their watts/lamp and costs are adjusted to reflect the technology's lumen output compared to the hybrid baseline technology. If a technology has a lower lumen output than the hybrid baseline technology the watts/lamp and costs are adjusted upward to get an equivalent lumen output. In this way we are replacing the turned over stock with an equivalent amount of light. There is no lumen adjustment for dimmable technologies as the savings from these technologies is due to a lower level of output light (20% dimmed). The LED technologies are also not lumen adjusted since the technologies are considered to provide equivalent light on working surfaces even though the lumen output may be lower.

It is assumed that all technologies have four lamps per fixture with the exception of two lamps per fixture for the T5 high output and induction technologies, and a single unit replacement for the LED fixture and future technology which are integrated units (including the lighting technology and ballast in the fixture). The lighting future technology is assumed to have 110 lumens/watt of output light.

Table F-10
Commercial Indoor Linear Fluorescent Lighting Measures

	Watts	Lumens	Fixture Cost	Ballast Cost	Lamp Cost	Life (hours)
T12	40	2,650	$19.00	$19.40	$1.65	20,000
T8	32	2,950	$19.00	$18.00	$2.00	20,000
T5	27	2,900	$68.00	$28.00	$2.00	20,000
T5 High Output	54	5,000	$99.00	$28.00	$6.50	20,000
Super T8	32	3,100	$19.00	$18.00	$3.00	20,000
T8 (Dimmable)	26	2,360	$19.00	$40.00	$2.00	20,000
T5 (Dimmable)	22	2,320	$68.00	$40.00	$2.00	20,000
Linear LED	22	2,110	-	-	$65.00	40,000
LED Fixture	60	5,145	$500.00	-	-	70,000
Induction	60	5,050	$325.00	-	$33.00	100,000
Future Technology	47	5,145	$500.00	-	-	70,000

Note: Watts and lumens data are per lamp. The linear LED technology is a tube replacement where existing T12 and T8 lamps are replaced one-for-one with LED tube lamps. LED = light emitting diode

The final indoor lighting segment is high-intensity discharge lighting (HID). This is treated separately from screw-in lighting and linear fluorescent. Measure data is shown in Table F-11.

Table F-11
Commercial HID Lighting Measures

	Watts	Lumens	Fixture Cost	Ballast Cost	Lamp Cost	Life (hours)
Baseline – Metal Halide w/ Magnetic Ballast	400	42,000	$250.00	$50.00	$27.00	20,000
Metal Halide w/ Electronic Ballast	250	22,000	$250.00	$120.00	$35.00	20,000
Induction Retrofit (kit w/ ballast and lamp)	400	16,000	$0.00	$114.00	$116.00	80,000
Induction	250	16,000	$250.00	$114.00	$116.00	80,000
T8 (high bays w/ reflectors)	200	18,900	$137.00	$20.00	$18.00	36,000
T5 (high bays w/ reflectors)	200	20,000	$137.00	$20.00	$18.00	36,000
LED	150	11,090	$800.00	$0.00	$0.00	50,000

Note: Watts and lumens data are per fixture. LED = light emitting diode

Outdoor street and area lighting are treated separately in commercial. Measure data is shown in Table F-12. The stock is split between two baseline technologies, 250 W metal halide fixtures and 400 W high-pressure sodium/metal halide fixtures. The replacement technologies are LED fixtures with 60 W and 158 W respectively. These are assumed to provide the same amount of useful light output as the technology they are replacing.

Table F-12
Commercial Outdoor Lighting Measures

	Watts/ Fixture	Base Cost	Incremental Cost	Life (hours)
Baseline – Metal Halide	250	$465.00	-	70,000
Efficient – 60 W LED	60	$640.00	$175.00	70,000
Baseline – High-Pressure Sodium/ Mercury Vapor	400	$590.00	-	70,000
Efficient – 158 W LED	158	$790.00	$200.00	70,000

Note: Watts and lumens data are per fixture. LED = light emitting diode

Commercial Application Factors

The application factors apply to secondary measures; when a measure passes the economic screen the energy and demand savings, incremental cost, and base cost are scaled using the application factors for inclusion in end-use impacts and costs. The un-saturation, applicability and feasibility do not apply to primary measures instead these factors are captured in the end-use saturation. Note that the un-saturation is the percent of building space that does not currently have this measure installed. I.e., if a measure has 40% un-saturation then 40% of the building space does *not* have the measure present. Commercial measures application factors are shown in Table F-13.

Table F-13
Commercial Application Factors

Measure	Un-Saturation	Applica-bility	Feasi-bility
Heat Pump (Heating and Cooling) and Central AC			
Economizer	33%	77%	90%
Duct Insulation	25%	77%	90%
EMS	24%	77%	90%
Programmable Thermostat	25%	77%	100%
Duct Testing and Sealing	25%	18%	100%
Cool Roof	10%	15%	100%
Roof Insulation	12%	77%	100%
Efficient Windows	60%	77%	100%
HVAC Retrocommissioning	17%	77%	100%
Heat Pump (Heating and Cooling) and Chiller			
EMS	24%	77%	90%
HVAC Retrocommissioning	17%	77%	100%
Chiller Space Cooling			
VSD on Pump	5%	18%	100%
Variable Air Volume System	30%	100%	90%
Ventilation			
Energy-Efficient Motors	25%	77%	90%
Variable Speed Control	25%	77%	90%
Water Heating			
Water Temperature Reset	5%	18%	100%

Table F-13 (continued)
Commercial Application Factors

Measure	Un-Saturation	Applica-bility	Feasi-bility
Refrigeration			
High-Efficiency Compressor	25%	4%	100%
Anti-Sweat Heater Controls	25%	4%	100%
Floating Head Pressure Controls	25%	4%	100%
Installation of Glass Doors	25%	4%	100%
High-Efficiency Vending Machine	2%	10%	100%
Icemakers	15%	4%	100%
Reach-in Coolers and Freezers	15%	4%	100%

Note: EMS = energy management system; AC = air conditioning; VSD = variable speed drive; HVAC = heating, ventilation, and air conditioning; AC = air conditioning

Commercial MARs and PIFs

The market acceptance ratios (MARs) and program implementation factors (PIFs) apply at the measure level. For measures with multiple technology choices the same MARs and PIFs are applied regardless of the winning technology. They are specified for 2010, 2020, and 2030 and are interpolated/extrapolated for other years, with a minimum of 0% and maximum of 100%.

The MARs are used to scale the economic potential energy and demand impacts, and costs for the winning measures to find the high achievable potential. This is done at the measure level and summed to the end-use level for use in the stock turnover.

The PIFs are used to scale the high achievable potential energy and demand impacts, and costs for the winning measures to find the achievable potential. This is also done at the measure level and summed to the end-use level for use in the stock turnover. The commercial MARs and PIFs are shown in Table F-14 and Table F-15 respectively. Primary measures in weather-sensitive end uses may have different MARs and PIFs by Census region.

Table F-14
Commercial Market Acceptance Ratios (MARs)

Measure	Northeast			South			Midwest			West		
	2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030
Heat pump	50%	75%	100%	50%	75%	100%	50%	75%	100%	50%	75%	100%
Economizer (HP and CAC)	26%	77%	78%	25%	76%	76%	25%	75%	76%	25%	76%	76%
Duct Insulation (HP and CAC)	31%	88%	88%	30%	86%	86%	30%	86%	86%	30%	86%	86%
EMS (HP and chiller)	26%	77%	78%	25%	76%	76%	25%	75%	76%	25%	76%	76%
Programmable Thermostat (HP and CAC)	26%	77%	78%	25%	76%	76%	25%	75%	76%	25%	76%	76%
Duct Testing and Sealing (HP and CAC)	31%	88%	88%	30%	86%	86%	30%	86%	86%	30%	86%	86%
Cool Roof (HP and CAC)	31%	88%	88%	30%	86%	86%	30%	86%	86%	30%	86%	86%
Roof Insulation (HP and CAC)	31%	88%	88%	30%	86%	86%	30%	86%	86%	30%	86%	86%
Efficient Windows (HP and CAC)	31%	88%	88%	30%	86%	86%	30%	86%	86%	30%	86%	86%
HVAC Retro. (HP and chiller)	31%	88%	88%	30%	86%	86%	30%	86%	86%	30%	86%	86%
Central AC	50%	75%	100%	50%	75%	100%	50%	75%	100%	50%	75%	100%
Chiller	31%	88%	88%	30%	86%	86%	30%	86%	86%	30%	86%	86%
VSD on Pump (chiller)	26%	77%	78%	25%	76%	76%	25%	75%	76%	25%	76%	76%

Note: HP = heat pump (space heating and cooling); CAC = central air conditioning; EMS = energy management system; HVAC = heating, ventilation and air conditioning; VSD = variable speed drive

Table F-14 (continued)
Commercial Market Acceptance Ratios (MARs)

Measure	Northeast			South			Midwest			West		
	2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030
Variable Air Volume System (chiller)	26%	77%	78%	25%	76%	76%	25%	75%	76%	25%	76%	76%
Ventilation, Energy-Efficient Motors	26%	77%	78%	25%	76%	76%	25%	75%	76%	25%	76%	76%
Ventilation, Variable Speed Fan Control	26%	77%	78%	25%	76%	76%	25%	75%	76%	25%	76%	76%
Water Heater	5%	28%	50%	5%	28%	50%	5%	28%	50%	5%	28%	50%
Water Temperature Reset	31%	88%	88%	30%	86%	86%	30%	86%	86%	30%	86%	86%
High Efficiency Compressor	31%	88%	88%	30%	86%	86%	30%	86%	86%	30%	86%	86%
Anti-Sweat Heater Controls	31%	88%	88%	30%	86%	86%	30%	86%	86%	30%	86%	86%
Floating Head Pressure Controls	31%	88%	88%	30%	86%	86%	30%	86%	86%	30%	86%	86%
Installation of Glass Doors	31%	77%	78%	30%	76%	76%	30%	75%	76%	30%	76%	76%
High-Efficiency Vending Machine	26%	77%	78%	25%	76%	76%	25%	75%	76%	25%	76%	76%
Icemakers	31%	88%	88%	30%	86%	86%	30%	86%	86%	30%	86%	86%
Reach-in Coolers and Freezers	31%	88%	88%	30%	86%	86%	30%	86%	86%	30%	86%	86%
Screw-In Lighting	90%	93%	95%	90%	93%	95%	90%	93%	95%	90%	93%	95%
Linear Fluorescent Lighting	60%	78%	95%	60%	78%	95%	60%	78%	95%	60%	78%	95%

Table F-14 (continued)
Commercial Market Acceptance Ratios (MARs)

Measure	Northeast			South			Midwest			West		
	2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030
HID Lighting	60%	78%	95%	60%	78%	95%	60%	78%	95%	60%	78%	95%
Outdoor Lighting	60%	80%	100%	60%	80%	100%	60%	80%	100%	60%	80%	100%
Personal Computers	52%	88%	88%	51%	86%	86%	50%	86%	86%	51%	86%	86%
Servers	52%	88%	88%	51%	86%	86%	50%	86%	86%	51%	86%	86%
Monitors	52%	88%	88%	51%	86%	86%	50%	86%	86%	51%	86%	86%
Copiers Printers	52%	88%	88%	51%	86%	86%	50%	86%	86%	51%	86%	86%
Other Electronics	52%	88%	88%	51%	86%	86%	50%	86%	86%	51%	86%	86%

Note: HID = high-intensity discharge

Table F-15
Commercial Program Implementation Factors (PIFs)

Measure	Northeast			South			Midwest			West		
	2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030
Heat pump	50%	75%	100%	50%	75%	100%	50%	75%	100%	50%	75%	100%
Economizer (HP and CAC)	12%	31%	50%	8%	29%	50%	10%	30%	50%	15%	33%	50%
Duct Insulation (HP and CAC)	12%	26%	40%	8%	24%	40%	10%	25%	40%	15%	27%	40%
EMS (HP and chiller)	16%	33%	50%	10%	30%	50%	13%	31%	50%	20%	35%	50%
Programmable Thermostat (HP and CAC)	16%	33%	50%	10%	30%	50%	13%	31%	50%	20%	35%	50%

Table F-15 (continued)
Commercial Program Implementation Factors (PIFs)

Measure	Northeast			South			Midwest			West		
	2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030
Duct Testing and Sealing (HP and CAC)	12%	26%	40%	8%	24%	40%	10%	25%	40%	15%	27%	40%
Cool Roof (HP and CAC)	8%	24%	40%	5%	23%	40%	7%	23%	40%	10%	25%	40%
Roof Insulation (HP and CAC)	12%	26%	40%	8%	24%	40%	10%	25%	40%	15%	27%	40%
Efficient Windows (HP and CAC)	12%	26%	40%	8%	24%	40%	10%	25%	40%	15%	27%	40%
HVAC Retro. (HP and chiller)	8%	29%	50%	5%	27%	50%	7%	28%	50%	10%	30%	50%
Central AC	50%	75%	100%	50%	75%	100%	50%	75%	100%	50%	75%	100%
Chiller	20%	40%	60%	13%	36%	60%	16%	38%	60%	25%	42%	60%
VSD on Pump (chiller)	16%	38%	60%	10%	35%	60%	13%	37%	60%	20%	40%	60%
Variable Air Volume System (chiller)	8%	24%	40%	5%	23%	40%	7%	23%	40%	10%	25%	40%
Ventilation, Energy-Efficient Motors	20%	48%	75%	13%	44%	75%	16%	46%	75%	25%	50%	75%
Ventilation, Variable Speed Fan Control	20%	48%	75%	13%	44%	75%	16%	46%	75%	25%	50%	75%
Water Heater	33%	42%	50%	33%	42%	50%	33%	42%	50%	33%	42%	50%
Water Temperature Reset	16%	38%	60%	10%	35%	60%	13%	37%	60%	20%	40%	60%

Note: HP = heat pump (space heating and cooling); CAC = central air conditioning; EMS = energy management system; HVAC = heating, ventilation and air conditioning; VSD = variable speed drive

Table F-15 (continued)
Commercial Program Implementation Factors (PIFs)

Measure	Northeast			South			Midwest			West		
	2010	2020	2030	2010	2020	2030	2010	2020	2030	2010	2020	2030
High Efficiency Compressor	12%	26%	40%	8%	24%	40%	10%	25%	40%	15%	27%	40%
Anti-Sweat Heater Controls	12%	26%	40%	8%	24%	40%	10%	25%	40%	15%	27%	40%
Floating Head Pressure Controls	12%	26%	40%	8%	24%	40%	10%	25%	40%	15%	27%	40%
Installation of Glass Doors	12%	26%	40%	8%	24%	40%	10%	25%	40%	15%	27%	40%
High-Efficiency Vending Machine	12%	26%	40%	8%	24%	40%	10%	25%	40%	15%	27%	40%
Icemakers	4%	27%	50%	3%	26%	50%	3%	27%	50%	5%	27%	50%
Reach-in Coolers and Freezers	8%	29%	50%	5%	27%	50%	7%	28%	50%	10%	30%	50%
Screw-In Lighting	50%	63%	75%	50%	63%	75%	50%	63%	75%	50%	63%	75%
Linear Fluorescent Lighting	50%	75%	100%	50%	75%	100%	50%	75%	100%	50%	75%	100%
HID Lighting	50%	75%	100%	50%	75%	100%	50%	75%	100%	50%	75%	100%
Outdoor Lighting	50%	75%	100%	50%	75%	100%	50%	75%	100%	50%	75%	100%
Personal Computers	20%	48%	75%	13%	44%	75%	16%	46%	75%	25%	50%	75%
Servers	20%	48%	75%	13%	44%	75%	16%	46%	75%	25%	50%	75%
Monitors	16%	45%	75%	10%	42%	75%	13%	44%	75%	20%	48%	75%
Copiers Printers	16%	45%	75%	10%	42%	75%	13%	44%	75%	20%	48%	75%
Other Electronics	16%	45%	75%	10%	42%	75%	13%	44%	75%	20%	48%	75%

Note: HID = high-intensity discharge

Appendix G: Industrial Potential Data

Industrial efficiency savings are applied at the process level within each manufacturing segment. The savings applied are shown in Table G-1.

There are no savings for electro-chemical processes, material handling, materials processing and other processes.

Table G-1
Industrial Process-Level Potential Savings

Manufacturing Segment		Compressed Air	Industrial Facilities (Lighting, HVAC and Facility Support)	Fans and Blowers	Process Cooling and Refrigeration	Process Heating	Pumps	Steam Generation Equipment
311&312	Food, Beverage & Tobacco	5.0%	15.0%	10.0%	5.0%	5.0%	15.0%	5.0%
313-316	Clothing	5.0%	15.0%	10.0%	5.0%	5.0%	15.0%	5.0%
321&322	Wood Products Pulp & Paper	5.0%	15.0%	10.0%	5.0%	5.0%	15.0%	5.0%
323	Printing	5.0%	15.0%	10.0%	5.0%	5.0%	15.0%	5.0%
324	Petroleum and Coal Products	5.0%	15.0%	10.0%	5.0%	7.5%	15.0%	5.0%

Table G-1 (continued)
Industrial Process-Level Potential Savings

Manufacturing Segment		Compressed Air	Industrial Facilities (Lighting, HVAC and Facility Support)	Fans and Blowers	Process Cooling and Refrigeration	Process Heating	Pumps	Steam Generation Equipment
325	Chemicals & Allied Products	5.0%	15.0%	10.0%	5.0%	7.5%	15.0%	5.0%
326	Plastics	5.0%	15.0%	10.0%	5.0%	5.0%	15.0%	5.0%
327	Non-Metallic	5.0%	15.0%	10.0%	5.0%	10.0%	15.0%	0.0%
331	Primary Metals	5.0%	15.0%	10.0%	5.0%	10.0%	15.0%	0.0%
332	Fabricated Metals	5.0%	15.0%	10.0%	5.0%	7.5%	15.0%	5.0%
333	Machinery	5.0%	15.0%	10.0%	5.0%	5.0%	15.0%	5.0%
334	Computer Equipment	5.0%	15.0%	10.0%	5.0%	5.0%	15.0%	5.0%
335	Appliance Manufacturing	5.0%	15.0%	10.0%	5.0%	7.5%	15.0%	5.0%
336	Transportation Equipment	5.0%	15.0%	10.0%	5.0%	5.0%	15.0%	5.0%
337	Furniture	5.0%	15.0%	10.0%	5.0%	5.0%	15.0%	5.0%
339	Other	5.0%	15.0%	10.0%	5.0%	5.0%	15.0%	5.0%
	Total	5.0%	15.0%	10.0%	5.0%	5.0%	15.0%	5.0%

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The 2016 State Energy Efficiency Scorecard

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Executive Summary

The past year has been an exciting time for energy efficiency, with several states strengthening efficiency policies and programs, and policymakers publicly recognizing the diverse benefits these initiatives provide. Utilities across the United States invested approximately $7.7 billion in energy efficiency over the past year. Meanwhile, states are also spurring efficiency investment through advancements in building energy codes, transportation planning, and leading by example in their own facilities and fleets. These investments reap large benefits, giving businesses, governments, and consumers more control over how and when they use energy. While some uncertainty hangs over the EPA's Clean Power Plan as it awaits judicial review, many states continue to plan innovative strategies to reduce greenhouse gas (GHG) emissions through energy efficiency. As a cost-effective compliance option, efficiency is a valuable addition to any state's policy toolkit, saving money, driving investment across all sectors of the economy, creating jobs, and reducing the environmental impact of energy use.

Governors, legislators, regulators, businesses, and citizens are increasingly recognizing that energy efficiency is a critical state resource that keeps money in the local economy. As a result, many innovative policies and programs that promote energy efficiency originate at the state level. *The 2016 State Energy Efficiency Scorecard* reflects these successes through a comprehensive analysis of state efforts to support energy efficiency.

This is the 10th edition of the *Scorecard*. As in the past, this year's report ranks states on their policy and program efforts, not only assessing performance but also documenting best practices and recognizing leadership. By providing an annual benchmark of the progress of state energy efficiency policies, the *Scorecard* encourages states to continue strengthening their commitment to efficiency, thereby promoting economic growth and environmental benefits.

The 2016 *Scorecard* assesses state policies and programs that improve energy efficiency in our homes, businesses, industries, and transportation systems. It examines the six policy areas in which states typically pursue energy efficiency:

- Utility and public benefits programs and policies
- Transportation policies
- Building energy codes and compliance
- Combined heat and power (CHP) policies
- State government–led initiatives around energy efficiency
- Appliance and equipment standards

KEY FINDINGS

Figure ES1 shows the states' rankings, dividing them into five tiers for easy comparison. Later in this section, table ES1 provides details of each state's scores. An identical ranking for two or more states indicates a tie.

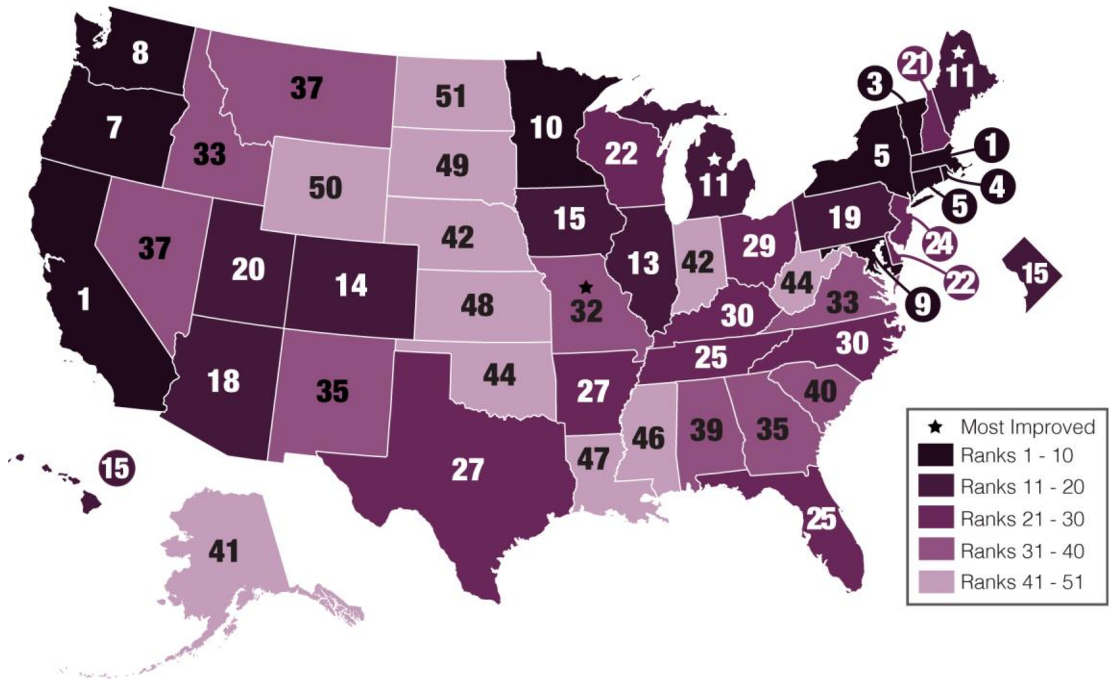

Figure ES1. *2016 State Scorecard* rankings

In a dramatic photo finish, **California** and **Massachusetts** tied for the top spot this year. This marks Massachusetts's sixth consecutive year in first place, but the first time it shared the spotlight with the Golden State (which last held the title in 2010). A perennial leader in many of the *Scorecard's* policy areas, California can credit this year's rise in the rankings to a notable increase in electricity savings thanks to strong policies designed to ramp up energy efficiency programs. For example, the California Clean Jobs Act allocates sizeable funding to energy efficiency projects in schools, and the state recently implemented a cap-and-trade program under the California Global Warming Solutions Act of 2006. California continued to raise the bar in 2015 with the passage of two bills: Senate Bill 350, which requires a doubling of energy efficiency savings from electricity and natural gas end-uses by 2030, and Assembly Bill 802, which promotes building benchmarking, enables access to whole-building data, and requires the California Energy Commission and the California Public Utilities Commission to reassess baselines for energy efficiency measures.

Massachusetts continues to make notable progress as well, recently increasing its electricity efficiency targets to almost 3% and adopting the newest IECC and ASHRAE standards as part of the ninth edition of the state's building energy codes. Much of the state's achievement is based on its continued commitment to energy efficiency under the Green Communities Act of 2008. Among other things, the legislation has spurred additional investment in energy efficiency programs by requiring utilities to save a large and growing percentage of energy every year through efficiency measures.

Joining California and Massachusetts in the top tier are **Vermont** and **Rhode Island**, followed by **Connecticut** and **New York** in a fifth-place tie. Each of these states has been among the leaders in the past, showing the continuing commitment and progress of the top-tier states.

Oregon, **Washington**, **Maryland**, and **Minnesota** rounded out the top 10 this year. Each of these states has well-established efficiency programs and continues to push the boundaries by redefining the ways in which policies and regulations can enable energy savings.

States Rising and Falling

The most-improved states this year were **Missouri**, **Maine**, and **Michigan**. They posted the largest point increases over their previous year's score.

With the most dramatic improvement of any state this year, **Missouri** added 5 points to leap an impressive 12 positions in the rankings. The Show-Me State showed improvements across the board, adding points in utility savings, transportation, building energy codes, CHP, and state government-led programs. For example, Missouri partnered with the Midwest Energy Efficiency Alliance to develop a compliance study of residential building energy codes. The state has also enabled several Property Assessed Clean Energy (PACE) programs, which allow local governments to provide financing for energy efficiency and renewable energy projects that property owners pay back through property tax assessments. In addition, efforts to strengthen energy efficiency are a cornerstone of Missouri's recently released 2015 Comprehensive State Energy Plan, which lays out a roadmap to continue to build upon the state's success.

Maine also added points thanks to its increased energy efficiency investments and the resulting electricity savings. Moving into its third Triennial Plan in 2017, Maine continues to raise the bar with its recent adoption of incremental electric efficiency targets of roughly 2.4%. While these targets are the fourth highest in the country, it is important to note that state lawmakers sent mixed messages this year by passing legislation to return a sizeable portion of Regional Greenhouse Gas Initiative (RGGI) revenues to certain large electric customers, funds that otherwise would have gone toward measures to strengthen efficiency and reduce greenhouse gas emissions.

Michigan also earned additional points in the building energy codes category, with its 2015 Residential Code taking effect earlier this year and new commercial codes expected to take effect next year. Also garnering points were a state-run LED conversion program for small businesses and not-for-profit organizations, as well as the state's commercial and industrial PACE efforts. We gave credit for PACE for the first time in this year's *Scorecard* to recognize innovative state efforts to leverage private capital toward efficiency goals.

Other states have also made progress in energy efficiency.

Rhode Island, which has ranked among the top five since 2014, moved out of its 2015 tie for fourth place to claim that spot solely for itself this year by scoring an additional 3 points. The Ocean State was the only one to earn a perfect score for utility and public benefits programs and policies, and it led all states in net incremental electricity savings as a percentage of retail sales. Rhode Island is poised to continue its success thanks to a strong and diverse portfolio of state government policies—including rebates, loan programs, and PACE financing—to encourage energy efficiency.

New York, which continues to lay the regulatory foundations for its utility system of the future through its Reforming the Energy Vision (REV) proceeding, posted an increase in electricity savings. Earlier in the year, the Empire State also completed major updates to its state building energy codes, incorporating the 2015 IECC and ASHRAE 90.1-2013 standards. **Utah** and **Tennessee** made similar gains thanks to updates to state building energy codes this year. **Arkansas** committed to extend its energy efficiency goals and gained points for state government-led policies, including a home energy loan program and PACE financing.

By contrast, 23 states fell in the rankings this year, and 21 lost points, both because of changes in their performance and adjustments to our methodology, including more emphasis on energy savings achieved by utilities. **Illinois** fell the farthest, losing 4.5 points and falling three positions in the rankings. This drop shows the need for states to consistently update and improve their policies. Although Illinois has energy savings targets in place, spending cannot exceed an established cost cap, so regulators have approved lower targets in recent years.

Results by Policy Area

Rhode Island, **Massachusetts**, and **Vermont** were the leading states in utility-sector energy efficiency programs and policies (see Chapter 2). These three states also topped this category in 2014 and 2015. With long records of success, all three continued to raise the bar on cost-effective programs and policies. Rhode Island earned maximum points in this category for the third year in a row by achieving incremental electricity savings of close to 3% of retail sales.

Savings from electricity efficiency programs in 2015 totaled approximately 26.5 million megawatt-hours (MWh), a 3.1% increase over the 2014 savings reported in last year's *State Scorecard*. These savings are equivalent to about 0.7% of total retail electricity sales across the nation. Gas savings for 2015 were reported at 345 million therms, an almost 8% decrease from 2014, likely due at least in part to historically low prices.

Total spending for electricity efficiency programs reached $6.3 billion in 2015. Adding this to natural gas program spending of $1.4 billion, we estimate total efficiency program expenditures of approximately $7.7 billion, an increase over the $7.3 billion reported for 2014.

Twenty-six states continue to enforce and adequately fund energy savings targets to drive investments in utility-sector energy efficiency programs. The states with the most aggressive targets included **Massachusetts**, **Rhode Island**, and **Arizona**. This year, **Massachusetts**, **Maine**, and **Connecticut** all adopted new and more stringent three-year savings targets, while **Arkansas** extended savings targets for both electricity and natural gas through 2019. Also making headlines was **New Hampshire**, which approved its long-awaited energy efficiency resource standard (EERS) in the summer. **New York**'s REV continues to take shape, although concrete long-range energy efficiency targets are still pending. Other states have faced challenges to their EERS policies. In **Ohio**, a freeze passed by state legislators continues through 2016, even though most utilities in the state are still meeting targets.

California, **Massachusetts**, and **New York** continue to lead the way in energy-efficient transportation policies (see Chapter 3). California's requirements for reducing GHG emissions have prompted several strategies for smart growth. Massachusetts promoted smart growth development in cities and municipalities through state-delivered financial incentives. New York is one of the few states in the nation to have a vehicle miles traveled (VMT) reduction target.

A variety of states joined **California** and **Illinois** in achieving top scores for building energy codes and compliance this year, including **Massachusetts**, **New York**, **Texas**, **Vermont**, and **Washington** (see Chapter 4). Only a few states have adopted or made progress toward adoption of the most recent DOE-certified codes for both residential and commercial new construction. These include **Illinois**, **Massachusetts**, **New Jersey**, **Utah**, **Vermont**, and **Washington**.

Massachusetts, **Maryland**, and **California** scored highest for their CHP policies (Chapter 5), while **California**, **Colorado**, **Connecticut**, **Massachusetts**, **Minnesota**, **New York**, **Tennessee**, and **Washington** led the way in state government initiatives (Chapter 6). All of these states offer financial incentives to consumers and state and local governments, and they also invest in R&D programs focused on energy efficiency.

California continues to lead the nation in setting appliance standards (Chapter 7), having adopted standards for more than 100 products. Within the past year, it became the first state to adopt standards for LEDs and small-diameter directional lamps; it also updated its standards for HVAC air filters, fluorescent dimming ballasts, and heat pump water chilling packages.

Table ES1 gives an overview of how states fared in each scoring category.

Table ES1. Summary of state scores in the *2016 State Scorecard*

Rank	State	Utility & public benefits programs & policies (20 pts.)	Trans-portation policies (10 pts.)	Building energy codes (7 pts.)	Combined heat & power (4 pts.)	State government initiatives (7 pts.)	Appliance efficiency standards (2 pts.)	TOTAL SCORE (50 pts.)	Change in rank from 2015	Change in score from 2015
1	California	15	10	7	4	7	2	**45**	1	1.5
1	Massachusetts	19.5	8.5	7	4	6	0	**45**	0	1
3	Vermont	19	7	7	2	5	0	**40**	0	0.5
4	Rhode Island	20	6	5	3.5	5	0	**39.5**	0	3
5	Connecticut	14.5	6.5	5.5	2.5	6	0.5	**35.5**	1	0
5	New York	10.5	8.5	7	3.5	6	0	**35.5**	4	3
7	Oregon	11.5	8	6.5	2.5	5.5	1	**35**	-3	-1.5
8	Washington	10.5	8	7	2.5	6.5	0	**34.5**	0	1
9	Maryland	9.5	6.5	6.5	4	5.5	0	**32**	-2	-3
10	Minnesota	12.5	4	6	2.5	6	0	**31**	0	0
11	Maine	10.5	5.5	3	3	5	0	**27**	3	3.5
11	Michigan	10.5	4	6.5	1.5	4.5	0	**27**	3	3.5
13	Illinois	8.5	5	7	2	4	0	**26.5**	-3	-4.5
14	Colorado	7.5	4.5	5	1	6	0.5	**24.5**	-2	0
15	DC	5.5	7.5	6	1	4	0	**24**	-1	0.5
15	Hawaii	11.5	4.5	4	1	3	0	**24**	4	2.5
15	Iowa	10	3	6	1.5	3.5	0	**24**	-3	-0.5
18	Arizona	10.5	3	3	1.5	3	0	**21**	-1	-1
19	Pennsylvania	3.5	5	4.5	2.5	5	0	**20.5**	-2	-1.5
20	Utah	7	2	5.5	1	4.5	0	**20**	3	3
21	New Hampshire	9.5	1.5	4	1	3.5	0	**19.5**	-1	0
22	Delaware	1	6.5	5.5	1.5	4.5	0	**19**	2	2.5
22	Wisconsin	8	1.5	4	1.5	4	0	**19**	0	1
24	New Jersey	4	6	4	1.5	2	0	**17.5**	-3	-1.5
25	Florida	1	5	5.5	1	3.5	0	**16**	2	0.5
25	Tennessee	1	5	3	1	6	0	**16**	6	3
27	Arkansas	7	1	4	0	3.5	0	**15.5**	4	2.5
27	Texas	0	2.5	7	1.5	4.5	0	**15.5**	-1	-0.5
29	Ohio	6.5	0	3	1.5	4	0	**15**	-2	-0.5
30	Kentucky	3	1	5	0.5	5	0	**14.5**	-1	0.5
30	North Carolina	2	3.5	4	1	4	0	**14.5**	-6	-2
32	Missouri	2	2.5	3	1	5	0	**13.5**	12	5
33	Idaho	3.5	1	5	0.5	3	0	**13**	-4	-1
33	Virginia	-0.5	4.5	4	0	5	0	**13**	-2	0
35	Georgia	1.5	4.5	3.5	0.5	2.5	0	**12.5**	2	0
35	New Mexico	4	0.5	3.5	1.5	3	0	**12.5**	-4	-0.5
37	Montana	2	0.5	5	1	3.5	0	**12**	-6	-1
37	Nevada	3	0.5	4	0.5	4	0	**12**	-6	-1
39	Alabama	2	0	6	0	3	0	**11**	2	1.5
40	South Carolina	1	3	3	0	3.5	0	**10.5**	0	0.5
41	Alaska	0	2	2	1	5	0	**10**	1	1
42	Indiana	4	1.5	2	0.5	1.5	0	**9.5**	-4	-1.5
42	Nebraska	1.5	0.5	5	0	2.5	0	**9.5**	0	0.5
44	Oklahoma	3.5	1	2	0	1.5	0	**8**	-6	-3
44	West Virginia	-0.5	3	4.5	0.5	0.5	0	**8**	1	0
46	Mississippi	1	1	1.5	0.5	3	0	**7**	1	-0.5
47	Louisiana	0.5	1.5	2.5	0.5	1.5	0	**6.5**	1	0.5
48	Kansas	0	1	1.5	0.5	3	0	**6**	-3	-2
49	South Dakota	2.5	0.5	0.5	0.5	1	0	**5**	-1	-1
50	Wyoming	0.5	1	1	0	2	0	**4.5**	0	-1
51	North Dakota	0	1	1	0.5	0.5	0	**3**	0	-1

As in 2015, we included three US territories in our research this year: Puerto Rico, Guam, and the US Virgin Islands. While we did score these territories, we did not include them in our general rankings. All of them have taken some steps toward ensuring that building energy codes meet the requirements of the American Recovery and Reinvestment Act, but they have yet to invest heavily in energy efficiency in other sectors. The best-performing of these, Puerto Rico, would rank 44th if it were a state. Table ES2 shows their scores.

Table ES2. Summary of scores for US territories in the *2016 State Scorecard*

Territory	Utility & public benefits programs & policies (20 pts.)	Transportation policies (10 pts.)	Building energy codes (7 pts.)	Combined heat & power (4 pts.)	State government initiatives (7 pts.)	Appliance efficiency standards (2 pts.)	**TOTAL SCORE (50 pts.)**	Change in score from 2015
Puerto Rico	0	2.5	2.5	0.5	2.5	0	**8**	1
Guam	0	0.5	3	0	1	0	**4.5**	1
US Virgin Islands	0	0	2.5	0	0.5	0	**3**	0

Strategies for Improving Energy Efficiency

Establish and adequately fund an EERS or similar energy savings target. EERS policies set specific energy savings targets that utilities or independent statewide program administrators must meet through customer energy efficiency programs. They serve as an enabling framework for cost-effective investment, savings, and program activity. EERS policies can catalyze increased energy efficiency and its associated economic and environmental benefits.

Examples: Massachusetts, Maine, Arizona, Hawaii, Rhode Island

Adopt updated, more stringent building energy codes, improve code compliance, and involve efficiency program administrators in code support. Buildings use more than 40% of the total energy consumed in the United States, making them an essential target for energy savings. Mandatory building energy codes are one way to ensure a minimum level of energy efficiency for new residential and commercial buildings.

Examples: California, Maryland, Illinois, Texas

Set quantitative targets for reducing VMT, and integrate land use and transportation planning. Like buildings, transportation consumes a substantial portion of the total energy used in the United States. Although the recent federal fuel economy standards will go a long way in helping to reduce fuel consumption, states will realize even greater energy savings by codifying targets for reducing VMT as well as integrating land use and transportation planning to create sustainable communities with access to multiple modes of transportation.

Examples: California, New York, Massachusetts, Oregon

Treat cost-effective and efficient CHP as an energy efficiency resource equivalent to other forms of energy efficiency. Many states list CHP as an eligible technology within their EERS or renewable portfolio standard, but they relegate it to a bottom tier. ACEEE recommends that states give CHP savings equal footing, which requires that they develop a specific methodology for counting energy savings attributed to its utilization. If CHP is allowed as an eligible resource, EERS target levels should be increased to account for CHP potential and to ensure that CHP does not displace traditional energy efficiency measures.

Example: Massachusetts

Expand state-led efforts—and make them visible. Initiatives here might include establishing sustainable funding sources for energy efficiency incentive programs; investing in energy efficiency–related research, development, and demonstration centers; and leading by example by incorporating energy efficiency into government operations. States have many opportunities to lead by example, including reducing energy use in public buildings and fleets, demonstrating the market for energy service companies (ESCOs) that finance and deliver energy-saving projects, and funding research centers that focus on breakthroughs in energy-efficient technologies.

Examples: New York, Connecticut, Alaska

Explore and promote innovative financing mechanisms to leverage private capital and lower upfront costs of energy efficiency measures. Although utilities in many states offer some form of on-bill financing program to promote energy efficiency in homes and buildings, expanding lender and customer participation has been an ongoing challenge. States can help address this challenge by passing legislation, increasing stakeholder awareness, and addressing legal barriers to the implementation of financing programs. A growing number of states are seeking new ways to maximize the impact of public funds and invigorate energy efficiency by attracting private capital through emerging financing models such as PACE and green banks.

Examples: Missouri, New York, Rhode Island

Introduction

The past year has been an exciting time for energy efficiency, with several states strengthening energy efficiency policies and programs, and policymakers publicly recognizing the diverse benefits of these initiatives. Utilities across the United States invested approximately $7.7 billion in energy efficiency over the past year. States are also spurring energy efficiency investment through advancements in building energy codes, transportation planning, and leading by example in their own facilities and fleets. These investments in energy efficiency reap huge benefits, giving businesses, governments, and consumers more control over how and when they use energy. While some uncertainty hangs over the EPA's Clean Power Plan as it awaits judicial review, many states continue to plan smart strategies to reduce greenhouse gas (GHG) emissions. As a cost-effective compliance option, energy efficiency is a valuable addition to any state's policy toolkit, saving money, driving investment across all economic sectors, creating jobs, and reducing the environmental impact of energy use.

Governors, legislators, regulators, businesses, and citizens increasingly recognize that energy efficiency is a crucially important state resource that keeps their money in the local economies. As a result, many innovative policies and programs that promote energy efficiency originate at the state level. *The 2016 State Energy Efficiency Scorecard* reflects these successes through a comprehensive analysis of state efforts to support energy efficiency.

This is the 10th edition of the *State Energy Efficiency Scorecard*. As in the past, this year's *State Scorecard* ranks states on their policy and program efforts, not only assessing performance but also documenting best practices and recognizing leadership. The *State Scorecard* provides an annual benchmark of the progress of state energy efficiency policies and encourages states to continue strengthening their commitment to efficiency, thereby promoting economic growth and environmental benefits.

The *Scorecard* is divided into eight chapters. In Chapter 1, we discuss our methodology for scoring states (including changes made this year), present the overall results of our analysis, and provide several strategies states can use to improve their energy efficiency. Chapter 1 also highlights the leading states, most-improved states, and the policy trends revealed by the rankings.

Subsequent chapters present detailed results for six major policy areas. Chapter 2 covers utility and public benefits programs and policies. Chapter 3 discusses transportation policies. Chapter 4 deals with building energy code adoption and state code compliance efforts. Chapter 5 covers state scores on policies that encourage and enable combined heat and power (CHP) development. Chapter 6 deals with state government initiatives, including financial incentives, lead-by-example policies, energy efficiency–focused research and development (R&D), and building energy use transparency policies. Finally, Chapter 7 discusses appliance and equipment efficiency standards.

In Chapter 8, we offer our closing thoughts on the report's findings, expectations for what we will see from states in the coming year, and potential changes for next year's *State Scorecard*.

Chapter 1. Methodology and Results

Author: Weston Berg

SCORING

States are the test beds for policies and regulations, and no two states are the same. To reflect this diversity, we chose metrics that are flexible enough to capture the range of policy and program options that states use to encourage energy efficiency. The policies and programs evaluated in the *State Scorecard* aim to reduce end-use energy consumption, set long-term commitments for energy efficiency, and establish mandatory performance codes and standards. They also help to accelerate the adoption of the most energy-efficient technologies, reduce market, regulatory, and information barriers to energy efficiency, and provide funding for efficiency programs.

Table 1 lists six of the primary policy areas in which states have historically pursued energy efficiency:

- Utility and public benefits programs and policies[1]
- Transportation policies
- Building energy codes
- Policies encouraging CHP systems
- State government–led initiatives around energy efficiency
- Appliance and equipment standards

Table 1. Scoring by policy area and metrics

Policy areas and metrics	Maximum score	% of total points
Utility and public benefits programs and policies	20	40%
Incremental savings from electricity efficiency programs	7	14%
Incremental savings from natural gas efficiency programs	3	6%
Spending on electricity efficiency programs	3	6%
Spending on natural gas efficiency programs	2	4%
Large customer opt-out programs*	(–1)	NA
Energy efficiency resource standards (EERSs)	3	6%
Performance incentives and fixed cost recovery	2	4%
Transportation policies	10	20%
Greenhouse gas (GHG) tailpipe emissions standards	1.5	3%
Electric vehicle (EV) registrations	1	2%
High-efficiency vehicle consumer incentives	0.5	1%
Targets to reduce vehicle miles traveled (VMT)	1	2%

[1] A public benefits fund provides long-term funding for energy efficiency initiatives, usually through a small surcharge on electricity consumption collected on customers' bills.

Policy areas and metrics	Maximum score	% of total points
Change in VMT	1	2%
Integration of transportation and land use planning	1	2%
Complete streets policies	1	2%
Transit funding	1	2%
Transit legislation	1	2%
Freight system efficiency goals	1	2%
Building energy codes	7	14%
Level of code stringency	4	8%
Code compliance study	1	2%
Code enforcement activities	2	4%
Combined heat and power	4	8%
Interconnection standards	0.5	1%
Policies to encourage CHP as a resource	2	4%
Additional incentives for CHP	0.5	1%
Additional policy support	1	2%
State government initiatives	7	14%
Financial incentives	3	6%
Energy disclosure policies	1	2%
Lead-by-example efforts in state facilities and fleets	2	4%
Research and development	1	2%
Appliance and equipment efficiency standards	2	4%
Maximum total score	50	100%

* Large customer opt-out programs allow a class of customers to withdraw from energy efficiency programs, reducing the potential savings available, so we deduct points for these policies.

We allocated points among the policy areas to reflect the relative magnitude of energy savings possible through the measures scored. We relied on an analysis of scholarly work and the judgment of ACEEE staff and outside experts about the impact of state policies on energy efficiency in the sectors we cover. A variety of cross-sector potential studies have informed our understanding of the energy savings available in each policy area, and in turn led to ongoing refinements in our scoring methodology (Geller et al. 2007; Neubauer et al. 2009, 2011; Eldridge, Elliott, and Vaidyanathan 2010; Molina et al. 2011; Hayes et al. 2014).

Of the 50 total points possible, we gave 40% (20 points) to utility and public benefits program and policy metrics, 14% (7 points) to building energy codes, and 8% (4 points) to improved CHP policies. We used the same methodology to allocate the other policy area points, awarding 10 points for transportation policies and programs and 2 points for state appliance and equipment standards. Savings from the policies and programs measured in our chapter on state initiatives are hard to quantify, but we assigned a significant number of points to this policy area to highlight states that lead by example in making clear and visible commitments to energy efficiency.

Within each policy area, we developed a scoring methodology based on a diverse set of criteria that we detail in each policy chapter. We used these criteria to assign a score to each state. The scores were informed by data requests sent to state energy officials, public utility commission staff, and experts in each policy area. To the best of our knowledge, policy information for *The 2016 State Energy Efficiency Scorecard* is accurate as of July 31, 2016.

The *State Scorecard* is meant to reflect the current policy landscape, incorporating changes from year to year. We do not envision that the allocation of points both across and within sectors will forever remain the same; rather, we will continue to adjust our methodology to reflect the current energy efficiency policy and program landscape. This year, we made changes to our scoring methodology in several policy areas. We outline these changes later in this chapter and discuss them in more depth in the relevant policy chapters. Changes in future editions of the *Scorecard* could include revisions to point allocations and the addition or subtraction of entire categories of scoring. In making these changes, our goal is to faithfully represent states' evolving efforts to realize the potential for energy efficiency in the systems and sectors of their economies.

STATE DATA COLLECTION AND REVIEW

We continue to improve our outreach to state-level stakeholders to verify the accuracy and comprehensiveness of the policy information that we use to score the states. As in past years, we asked each state utility commission to review statewide data for the customer-funded energy efficiency programs presented in Chapter 2 and the CHP policies detailed in Chapter 5. Forty-five state commissions responded, comparable to the number of responses we received last year. We also asked each state energy office to review information on transportation policies (Chapter 3), building energy codes (Chapter 4), CHP (Chapter 5), and state government–led initiatives (Chapter 6).

We received responses from energy offices in 43 states and 2 territories, slightly less than the response rate we achieved in 2015. In addition, we gave state energy office and utility commission officials the opportunity to review and submit updates to the material on ACEEE's State and Local Policy Database (ACEEE 2016).[2] We also asked them to review and provide comments on a draft version of *The 2016 State Energy Efficiency Scorecard* prior to publication. We used publicly available data and responses from prior years to evaluate states that did not respond to this year's data request or request for review. In addition, we convened expert working groups to provide further information on building energy codes and CHP policies in all states.

Best-Practice Policy and Performance Metrics

The scoring framework described above is our best attempt to represent the myriad efficiency metrics as a quantitative score. Converting spending data, energy savings data, and policy adoption metrics spanning six policy areas into one score clearly involves some

[2] Available at database.aceee.org.

oversimplification. Quantitative energy-savings performance metrics are confined mostly to programs run by utilities and third-party administrators using ratepayer funds. These programs are subject to strict evaluation, measurement, and verification standards. States engage in many other efforts to encourage efficiency, but such efforts are typically not evaluated with the same rigor, so it is difficult to capture comprehensive quantitative data for these programs.

Although our preference is to include metrics based on energy savings achieved in every sector, these data are not widely available. Therefore, with the exception of utility policies, we have not scored the other policy areas on reported savings or spending data attributable to a particular policy action. Instead, given the lack of consistent ex post data, we have developed best-practice metrics for scoring the states. Although these metrics do not score outcomes directly, they credit states that are implementing policies likely to lead to more energy-efficient outcomes. For example, we give credit for *potential* energy savings from improved building energy codes and appliance efficiency standards since *actual* savings from these policies are rarely evaluated. We have also attempted to reflect outcome metrics to the extent possible; for example, electric vehicle (EV) registrations and reductions in vehicle miles traveled (VMT) both represent positive outcomes of transportation policies. We include full discussions of the policy and performance metrics in each chapter.

AREAS BEYOND OUR SCOPE: LOCAL AND FEDERAL EFFORTS

Energy efficiency initiatives implemented by actors at the federal or local level or in the private sector (with the exception of investor-owned utilities [IOUs] and CHP facilities) generally fall outside the scope of this report. It is important to note that regions, counties, and municipalities have become actively involved in developing energy efficiency programs, a positive development that reinforces state-level efficiency efforts. ACEEE's biennial *City Energy Efficiency Scorecard* (Ribeiro et al. 2015) captures data on these local actions; we do not specifically track them in the *State Scorecard*. However a few *State Scorecard* metrics do capture local-level efforts, including the adoption of building codes and land-use policies, as well as state financial incentives for local energy efficiency efforts. We also include municipal utilities in our data set to the extent that they report energy efficiency data to the US Energy Information Administration (EIA), state public utility commissions, or other state and regional groups. As much as possible, however, we aim to focus specifically on state-level energy efficiency activities.

The *State Scorecard* has not traditionally covered private-sector investments in efficient technologies outside of customer-funded or government-sponsored energy efficiency initiatives, codes, or standards. However we do recognize the need for metrics that capture the rapidly growing role of private financing mechanisms in new utility business models. As Chapter 6 explains, we began to move this year's *Scorecard* in that direction by considering the existence of Property Assessed Clean Energy (PACE) programs and green banks in the scores for state financial incentives. While utility and public programs are critical to leveraging private capital, we found it challenging to develop an independent metric that measures the success of private-sector investment, given the absence of protocols for measuring and verifying energy savings. We hope that as the transparency and reliability of savings data from these private initiatives improve, they will play a larger, more quantifiable role in future *State Scorecards.*

CHANGES IN SCORING METHODOLOGY FROM LAST YEAR

We updated the scoring methodology in five policy areas this year to better reflect potential energy savings and changing policy landscapes.

In Chapter 2, "Utility and Public Benefits Programs and Policies," we increased our emphasis on achieved savings by awarding an additional point to electric savings (shifting 1 point away from spending). We refined the data request in an effort to access more and better data and to emphasize measured savings. These changes led to a redistribution of points in the electric savings category that effectively rewarded high-achieving states with more points than lower-performing states. Meanwhile, other states—particularly those showing lower net savings and lower investment in efficiency—might see a loss in points, even where there has been no significant change in savings from last year.

In Chapter 3, "Transportation," we made no major changes in point allocation, but we did update our scoring category for energy efficiency in state freight plans to correspond with the 2015 adoption of the Fixing America's Surface Transportation (FAST) Act, which supersedes the Moving Ahead for Progress in the 21st Century Act (MAP-21) requirements.

In Chapter 4, "Building Energy Codes," the scoring methodology remained largely unchanged, but we did update our section on building energy code stringency. Specifically, we tightened our assessment of code stringency, awarding points only to states that could demonstrate statewide or significant local adoption of at least 2009 IECC and ASHRAE 90.1-2007 codes for residential and commercial construction, respectively. Given the looming 2017 deadline under the America Recovery and Reinvestment Act (ARRA) for states to achieve 90% compliance with these model energy codes—and the fact there has been ample time to adopt them—we no longer give credit for lesser standards.

In Chapter 6, "State Government-Led Initiatives," we allocated additional points for state-run financial incentives. We also expanded our eligibility criteria in this category to recognize a growing state movement to leverage private dollars for energy efficiency through programs such as green banks and PACE financing.

In Chapter 7, "Appliance and Equipment Efficiency Standards," we updated the scoring methodology for appliance and equipment standards to emphasize savings from recent state standards. A state could still earn up to 2 points for appliance efficiency standards not presently preempted by federal standards, but we did not award points for standards with compliance dates predating 2013.

We discuss additional details on scoring, including changes to methodology, in each chapter.

2016 STATE ENERGY EFFICIENCY SCORECARD *RESULTS*

We present the results of the *State Scorecard* in Figure 1 and describe them more fully in Table 2. In this section, we also highlight some key changes in state rankings, discuss which states are making notable new commitments to energy efficiency, and provide a series of recommendations for states wanting to increase their energy efficiency.

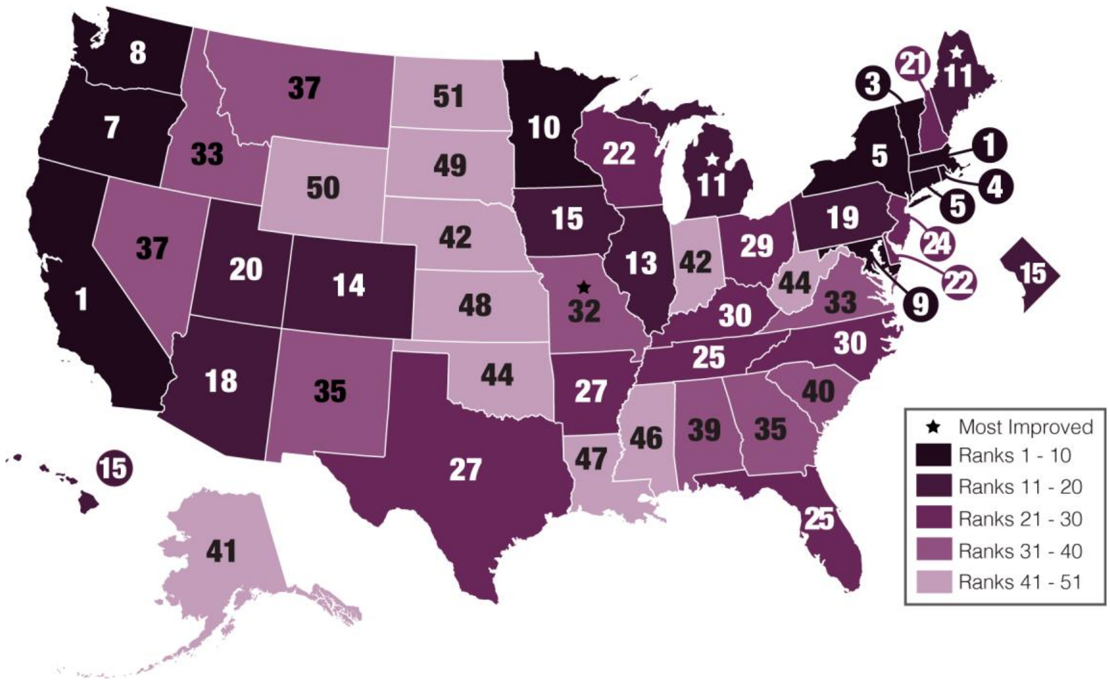

Figure 1. *2016 State Scorecard* rankings

Table 2. Summary of state scores in the *2016 State Scorecard*

Rank	State	Utility & public benefits programs & policies (20 pts.)	Trans-portation policies (10 pts.)	Building energy codes (7 pts.)	Combined heat & power (4 pts.)	State government initiatives (7 pts.)	Appliance efficiency standards (2 pts.)	**TOTAL SCORE (50 pts.)**	Change in rank from 2015	Change in score from 2015
1	California	15	10	7	4	7	2	**45**	1	1.5
1	Massachusetts	19.5	8.5	7	4	6	0	**45**	0	1
3	Vermont	19	7	7	2	5	0	**40**	0	0.5
4	Rhode Island	20	6	5	3.5	5	0	**39.5**	0	3
5	Connecticut	14.5	6.5	5.5	2.5	6	0.5	**35.5**	1	0
5	New York	10.5	8.5	7	3.5	6	0	**35.5**	4	3
7	Oregon	11.5	8	6.5	2.5	5.5	1	**35**	-3	-1.5
8	Washington	10.5	8	7	2.5	6.5	0	**34.5**	0	1
9	Maryland	9.5	6.5	6.5	4	5.5	0	**32**	-2	-3
10	Minnesota	12.5	4	6	2.5	6	0	**31**	0	0
11	Maine	10.5	5.5	3	3	5	0	**27**	3	3.5
11	Michigan	10.5	4	6.5	1.5	4.5	0	**27**	3	3.5
13	Illinois	8.5	5	7	2	4	0	**26.5**	-3	-4.5
14	Colorado	7.5	4.5	5	1	6	0.5	**24.5**	-2	0
15	District of Columbia	5.5	7.5	6	1	4	0	**24**	-1	0.5
15	Hawaii	11.5	4.5	4	1	3	0	**24**	4	2.5
15	Iowa	10	3	6	1.5	3.5	0	**24**	-3	-0.5
18	Arizona	10.5	3	3	1.5	3	0	**21**	-1	-1
19	Pennsylvania	3.5	5	4.5	2.5	5	0	**20.5**	-2	-1.5
20	Utah	7	2	5.5	1	4.5	0	**20**	3	3
21	New Hampshire	9.5	1.5	4	1	3.5	0	**19.5**	-1	0
22	Delaware	1	6.5	5.5	1.5	4.5	0	**19**	2	2.5
22	Wisconsin	8	1.5	4	1.5	4	0	**19**	0	1
24	New Jersey	4	6	4	1.5	2	0	**17.5**	-3	-1.5
25	Florida	1	5	5.5	1	3.5	0	**16**	2	0.5
25	Tennessee	1	5	3	1	6	0	**16**	6	3
27	Arkansas	7	1	4	0	3.5	0	**15.5**	4	2.5
27	Texas	0	2.5	7	1.5	4.5	0	**15.5**	-1	-0.5
29	Ohio	6.5	0	3	1.5	4	0	**15**	-2	-0.5
30	Kentucky	3	1	5	0.5	5	0	**14.5**	-1	0.5
30	North Carolina	2	3.5	4	1	4	0	**14.5**	-6	-2
32	Missouri	2	2.5	3	1	5	0	**13.5**	12	5
33	Idaho	3.5	1	5	0.5	3	0	**13**	-4	-1
33	Virginia	-0.5	4.5	4	0	5	0	**13**	-2	0
35	Georgia	1.5	4.5	3.5	0.5	2.5	0	**12.5**	2	0
35	New Mexico	4	0.5	3.5	1.5	3	0	**12.5**	-4	-0.5
37	Montana	2	0.5	5	1	3.5	0	**12**	-6	-1
37	Nevada	3	0.5	4	0.5	4	0	**12**	-6	-1
39	Alabama	2	0	6	0	3	0	**11**	2	1.5
40	South Carolina	1	3	3	0	3.5	0	**10.5**	0	0.5
41	Alaska	0	2	2	1	5	0	**10**	1	1
42	Indiana	4	1.5	2	0.5	1.5	0	**9.5**	-4	-1.5
42	Nebraska	1.5	0.5	5	0	2.5	0	**9.5**	0	0.5
44	Oklahoma	3.5	1	2	0	1.5	0	**8**	-6	-3
44	West Virginia	-0.5	3	4.5	0.5	0.5	0	**8**	1	0
46	Mississippi	1	1	1.5	0.5	3	0	**7**	1	-0.5
47	Louisiana	0.5	1.5	2.5	0.5	1.5	0	**6.5**	1	0.5
48	Kansas	0	1	1.5	0.5	3	0	**6**	-3	-2
49	South Dakota	2.5	0.5	0.5	0.5	1	0	**5**	-1	-1
50	Wyoming	0.5	1	1	0	2	0	**4.5**	0	-1
51	North Dakota	0	1	1	0.5	0.5	0	**3**	0	-1

As in previous years, we did not rank the three territories we included in our research this year, but we did score them in all categories. In general, territories scored near the bottom, largely because their publicly owned utilities do not offer energy efficiency programs. Although all three territories have taken some steps toward ensuring building energy codes are in place, they have not invested heavily in energy efficiency in other sectors. Table 3 shows scores for Puerto Rico, Guam, and the US Virgin Islands. Puerto Rico scores highest among territories, although it would rank only 44th if included in the general scoring table.

Table 3. Scores for US territories in the *2016 State Scorecard*

Territory	Utility & public benefits programs & policies (20 pts.)	Trans-portation policies (10 pts.)	Building energy codes (7 pts.)	Combined heat & power (4 pts.)	State government initiatives (7 pts.)	Appliance efficiency standards (2 pts.)	**Total score (50 pts.)**	Change in score from 2015
Puerto Rico	0	2.5	2.5	0.5	2.5	0	**8**	1
Guam	0	0.5	3	0	1	0	**4.5**	1
US Virgin Islands	0	0	2.5	0	0.5	0	**3**	0

How to Interpret Results

Although we provide individual state scores and rankings, the differences among states are most instructive in tiers of 10. The difference between states' total scores in the middle tiers of the *State Scorecard* is relatively small: just 5 and 3 points in the third and fourth tiers, respectively. These tiers also have a significant number of states tied in the rankings. For example, 22nd place is shared by Delaware and Wisconsin, while Georgia and New Mexico share 35th place. For the states in these two tiers, small improvements in energy efficiency will likely have a significant effect on their rankings. Conversely, idling states will easily fall behind as other states in this large group ramp up efficiency efforts.

The top tier, however, exhibits more variation in scoring, with a 14-point range, representing a third of the total variation in scoring among all the states. California and Massachusetts continued to score higher than other states, tying for the top spot. Other states in the top tier are also well-established high scorers. Generally speaking, the highest ranking states have all made broad, long-term commitments to energy efficiency, indicated by their staying power at the top of the *State Scorecard* over the past eight years. However it is important to note that retaining one's spot in the lead pack is no easy task, and that all of these states must embrace new, cutting-edge strategies and programs to remain at the top. Notably, the top tier did see some movement this year, with New York moving up four spots, California and Connecticut each moving up one spot, and Oregon and Maryland each dropping several positions.

2016 Leading States

After five consecutive years in second place, California earned its highest score since 2010 to join Massachusetts in a dead heat for first place. The Golden State earned perfect scores for transportation, building energy codes, CHP, state government-led initiatives, and appliance and equipment efficiency standards, all areas in which it has long led the pack. What really made the difference in lifting the state into first place was a notable increase in electricity savings thanks to strong policies designed to ramp up energy efficiency programs.

Through the California Clean Jobs Act (Proposition 39), the state has allocated sizeable funding to energy efficiency projects in schools. The state also began implementing a cap-and-trade program (required by the California Global Warming Solutions Act of 2006) in 2013. Energy efficiency makes up a significant portion of the state's strategy for meeting this program's GHG emissions-reduction goals. California continues to look to the future, having recently enacted two pieces of efficiency-spurring legislation: Senate Bill 350, requiring a doubling of energy efficiency savings from electricity and natural gas end-uses by 2030, and Assembly Bill 802, which promotes building benchmarking and enables access to whole-building data for buildings above a certain size.

Massachusetts also made progress this year, raising its score by 1 point, but not quite enough to hold off California. The increase coincided with the Bay State's efforts this year to adopt the IECC 2015 and ASHRAE standard 90.1-2013 as part of the ninth edition of the state's building energy codes. Massachusetts has a strong track record on energy efficiency. The state's Green Communities Act of 2008 laid the foundation for greater investments in energy efficiency programs by requiring gas and electric utilities to save a large and growing percentage of energy every year through energy efficiency. Its 2013 to 2015 electricity and gas savings goals were the most aggressive in the country, and this year Massachusetts continued to raise the bar by finalizing electricity efficiency targets approaching 3% for its next three-year cycle and increasing its annual natural gas target to 1.24% (MA EEAC 2015).

Vermont ranks third this year, the same place it held in 2015, due to its strong performance across nearly every policy area. Rhode Island, in fourth, achieved the highest electricity savings of any state, reporting statewide savings approaching 3%.

New York earned an additional 3 points to move into a tie with Connecticut for fifth place. Both states saw notable increases in electricity savings as a percentage of sales and made moves to update state building energy codes to more stringent model codes.

Table 4 shows the number of years that states have been in the top 5 and top 10 spots in the *State Scorecard* rankings since 2007.

Table 4. Leading states in the *State Scorecard*, by years at the top

State	Years in top 5	Years in top 10
California	10	10
Massachusetts	9	10
Oregon	9	10
Vermont	8	10
New York	7	10
Connecticut	5	10
Rhode Island	4	9
Washington	1	10
Minnesota	0	9
Maryland	0	6
Illinois	0	2
Maine	0	2
New Jersey	0	2
Wisconsin	0	1

In total, 8 states have occupied the top 5 spots, and 14 have appeared somewhere in the top 10 since the first edition of the *State Scorecard*. California is the only state to have held a spot among the top five in all 10 years, followed by Massachusetts and Oregon for nine years each, and Vermont for eight years. New Jersey, Wisconsin, Illinois, and Maine have all placed in the top 10 in the past, but none scored high enough to rank in the top tier this year.

Changes in Results Compared with *The 2015 State Energy Efficiency Scorecard*

Changes in states' overall scores this year compared to previous *State Scorecard*s stem not only from changes in states' efforts to improve energy efficiency but also from modifications to our scoring methodology. Therefore, variations from last year's rankings are not solely due to changes in states' efforts. Given the number of metrics in the *State Scorecard* and states' varying efforts, relative movement among the states should be expected.

Table 5 compares the results of *The 2016 State Energy Efficiency Scorecard* to last year's results.

Table 5. Number of states and territories gaining or losing points compared with 2015, by policy area

Policy category	States gaining points		No change		States losing points	
Utility & public benefits	13	24%	17	31%	24	44%
Transportation	11	20%	25	46%	18	33%
Building energy codes	22	41%	26	48%	6	11%
Combined heat and power	10	19%	38	70%	6	11%
State government initiatives	24	44%	19	35%	11	20%
Appliance standards	0	0%	45	83%	9	17%
Total score	25	46%	8	15%	21	39%

Percentages may not total 100 due to rounding.

Overall, 25 states and territories gained points and 21 states lost points compared with last year. Seven states and one territory had no change in score.[3] Some of the changes in points were due to our methodological changes, and so the number of states losing points should not necessarily be interpreted as a sign that states are losing ground. Rather, we raised the bar and awarded points for more ambitious programs and policies, particularly in electricity savings and appliance and equipment standards.

The landscape for energy efficiency is clearly in constant flux, and many opportunities remain for states to lead the way. The changes in state scores reflect an ever-rising bar for energy efficiency policies and outcomes. For example, as Chapter 2 describes, 24 states lost points in utility and public benefits programs and policies. This overall decrease reflects our added emphasis on performance metrics rather than spending metrics. That said, the general pattern is not indicative of a lack of progress among states. While several states have backslid in terms of policy—examples include Indiana's 2014 rollback of its energy efficiency resource standards (EERS) and Ohio's embattled EERS, which remains frozen as of summer 2016—most continued to make advances. Savings from electric efficiency programs in 2015 totaled approximately 26.5 million megawatt-hours (MWh), a 3.1% increase over the 2014 savings reported in last year's *State Scorecard*. These savings are equivalent to more than 0.7% of total retail electricity sales in the United States in 2015. More information on state scores for utility programs is included in Chapter 2.

Most-Improved States

Eighteen states rose in the rankings this year, and while all should be applauded, several made particularly noteworthy gains in overall points compared with last year.[4] This year's most improved states were Missouri, Maine, and Michigan. All of these states earned

[3] The *State Scorecard* looks at all 50 states and the District of Columbia, which, while not a state, is grouped under that heading for convenience. We also score, but do not rank, three US territories, including the US Virgin Islands.

[4] Note that change in rank reflects performance relative to other states. Change in score refers to absolute number of points earned.

significantly more points than last year to move up in the rankings. Table 6 shows changes in points and rank compared with last year for these states.

Table 6. Changes from 2015 for most-improved states*

	Change in score	Change in rank	2016 ranking	2015 ranking
Missouri	+5	+12	32	44
Maine	+3.5	+3	11	14
Michigan	+3.5	+3	11	14

* Most-improved standing is based on the change in a state's score compared with the previous year.

With the most dramatic improvement of any state this year, **Missouri** added 5 points to leap an impressive 12 positions in the rankings. The Show-Me State showed improvements across the board, adding points in utility savings, transportation, building energy codes, CHP, and state government-led programs. For example, Missouri partnered with the Midwest Energy Efficiency Alliance to develop a compliance study of residential building energy codes. It also has enabled several Property Assessed Clean Energy (PACE) programs. These allow local governments to provide financing for energy efficiency and renewable energy projects that property owners pay back through property tax assessments. In addition, efforts to strengthen energy efficiency are a cornerstone of Missouri's recently released 2015 Comprehensive State Energy Plan, which lays out a roadmap to continue to build upon the state's success.

Maine also added points thanks to its increased energy efficiency investments and the resulting electricity savings. As it moves into its third Triennial Plan in 2017, Maine continues to raise the stakes with its recent adoption of incremental electric efficiency targets of roughly 2.4%. While these targets are the fourth highest in the country, it is important to note that state lawmakers sent mixed messages this year by passing legislation to return a sizeable portion of Regional Greenhouse Gas Initiative (RGGI) revenues to certain large electric customers, funds that otherwise would have gone toward measures to strengthen efficiency and reduce greenhouse gas emissions.

Michigan also earned additional points in the building energy codes category, with its 2015 Residential Code taking effect earlier this year and new commercial codes expected to take effect next year. Also garnering points were a state-run LED conversion program for small businesses and not-for-profit organizations, as well the state's commercial and industrial PACE efforts. We gave credit for PACE for the first time in this year's *Scorecard* to recognize innovative state efforts to leverage private capital toward efficiency goals.

Rhode Island, which has ranked among the top five since 2014, moved out of its 2015 tie for fourth place to claim the spot solely for itself this year by scoring an additional 3 points. The Ocean State was the only one to earn a perfect score for utility and public benefits programs and policies, and it led all states in net incremental electricity savings as a percentage of retail sales. Rhode Island is poised to continue its success thanks to a strong and diverse portfolio of state government policies—including rebates, loan programs, and PACE financing—that encourage energy efficiency.

Other states have also made recent progress in energy efficiency.

New York, which continues to lay the regulatory foundations for its utility system of the future through its Reforming the Energy Vision (REV) proceeding, also posted an increase in electricity savings. Earlier in the year, the Empire State also completed major updates to its state building energy codes, incorporating the 2015 IECC and ASHRAE 90.1-2013 standards. **Utah** and **Tennessee** made similar gains thanks to updates to state building energy codes this year. **Arkansas** committed to extend its energy efficiency goals and gained points for state government-led policies, including a home energy loan program and PACE financing.

States Losing Ground

Twenty-three states fell in the rankings this year due to several factors, including policy or program rollbacks, faster progress by other states, and changes to the scoring methodology in four of our policy areas (utilities, transportation, CHP, and building codes). This loss of ground also indicates the complex relationship between changes in total score and changes in rank. Of the 21 states that lost points, 18 fell in the rankings.[5] The rankings of two others did not change, while one state, Mississippi, actually rose in the rankings despite losing points compared to last year. Meanwhile, Kentucky added to its score, but nonetheless fell in the rankings. Given the number of metrics covered in the *State Scorecard* and states' differing efforts, relative movement among states should be expected. As mentioned earlier, the difference among states' total scores, particularly in the third and fourth tiers of the *State Scorecard*, is small; as a result, idling states can easily fall behind in the rankings as others ramp up efforts to become more energy efficient.

Three states had the most noticeable overall drops in score compared with last year: Illinois lost 4.5 points, and Maryland and Oklahoma lost 3 points each. Illinois's fall illustrates the need to consistently update and improve policy. Although the state has energy savings targets in place, spending cannot exceed an established cost cap; as a result, regulators have approved lower targets in recent years. And although legislation provides for additional procurement of certain energy efficiency measures not subject to the cost cap, Illinois still has not kept pace with neighboring states such as Minnesota. Finally, for Illinois and other states, some of the loss in points can be attributed to updates in our scoring methodology, emphasizing total savings over amounts of utility ratepayer funds committed to energy efficiency.

Maryland lost points due to both a dip in electricity program savings and updates to our methodology. Meanwhile, Oklahoma's score was impacted by the state legislature's elimination of an Energy Efficient Residential Construction Tax Credit and the State Energy Facilities Program. Also figuring into its reduced score was the fact that its commercial

[5] The three US territories also lost points this year, but they are not included in our rankings.

building energy codes still reference the older 2006 IECC model code. The great majority of state building codes are at least as stringent as the 2009 IECC and ASHRAE 90.1-2007.

In general, we see two trends among these states and others losing ground in the *State Scorecard.* First, many of the states falling behind are not increasing energy savings year after year and are therefore being outpaced as other states ramp up programs to meet higher savings targets. These states typically have not fully implemented changes to the utility business model that encourage utilities to take full advantage of energy efficiency as a resource, including decoupling, performance incentives, and energy savings targets.

Secondly, opt-out provisions have been approved in many of the states falling behind in the *State Scorecard* rankings. These provisions allow large customers to avoid paying into energy efficiency programs, forcing other customers to subsidize them and limiting the amount of energy savings utilities can achieve.

STRATEGIES FOR IMPROVING ENERGY EFFICIENCY

No state received the full 50 points in *The 2016 State Energy Efficiency Scorecard*, reflecting the fact that opportunities remain in all states—including leading states—to improve energy efficiency. For states wanting to raise their standing in the *State Scorecard* and, more important, to capture greater energy savings and the associated public benefits, we offer the following recommendations based on the metrics we track.

Establish and adequately fund an EERS or similar energy savings target. These policies set specific energy savings targets that utilities or independent statewide program administrators must meet through customer energy efficiency programs and market transformation. They also serve as an enabling framework for cost-effective investment, savings, and program activity that, as seen in many of the leading states, can have a catalytic effect on increasing energy efficiency and its associated economic and environmental benefits. Although some states opt to include energy efficiency within the integrated resource planning (IRP) process, experience suggests that EERS policies truly drive higher cost-effective efficiency savings than any other method. The long-term goals associated with an EERS send a clear signal to market actors about the importance of energy efficiency resources in utility program planning, creating a level of certainty that encourages large-scale, productive investment in energy efficiency technologies and services. EERS targets should be established alongside rigorous, robust integrated and distributed resources planning. Long-term energy savings targets require leadership, sustainable funding sources, and institutional support to deliver on their goals. Chapter 2 has details.

Examples: Massachusetts, Arizona, Hawaii, Rhode Island

Adopt updated, more-stringent building energy codes, improve code compliance, and enable efficiency program administrators to be involved in code support. Buildings consume more than 40% of the total energy used in the United States, making them an essential target for energy savings. Mandatory building energy codes are one way to ensure a minimum level of energy efficiency for new residential and commercial buildings. Model codes are only as effective as their level of implementation, however, and improved compliance activities—including training and code-compliance surveys—are increasingly important. Another emerging policy driver for capturing energy savings from codes is the enabling of utility and program administrators to support compliance activities. See Chapter 4 for details.

Examples: California, Maryland, Illinois, Texas

Set quantitative targets for reducing VMT and integrate land use and transportation planning. Like buildings, transportation consumes a substantial portion of the total energy used in the United States. Although the recent federal fuel economy standards will go a long way in helping to reduce fuel consumption, states will realize even greater energy savings by addressing transportation system efficiency as a whole. Codifying targets for reducing VMT is an important step toward achieving substantial reductions in energy use, as is ensuring that states integrate land use and transportation planning to create sustainable communities with access to multiple modes of transportation.

Examples: California, New York, Massachusetts, Oregon

Treat cost-effective and efficient CHP as an energy efficiency resource equivalent to other forms of energy efficiency. Several states list CHP as an eligible technology in their EERS or renewable portfolio standard (RPS) but relegate it to a bottom tier, letting other renewable technologies and efficiency resources take priority within the standard. ACEEE recommends that CHP savings be given equal footing, which requires states to develop a specific methodology for counting CHP savings. If CHP is considered an eligible resource, total energy savings target levels should be increased to take CHP's potential into account. Massachusetts has accomplished this in its Green Communities Act.

Example: Massachusetts

Expand and highlight state-led efforts, such as funding for energy efficiency incentive programs, benchmarking requirements for state building energy use, and investments in energy efficiency–related R&D centers. State-led initiatives complement the existing landscape of utility programs, leveraging resources from the state's public and private sectors to generate energy and cost savings that benefit taxpayers and consumers. States have many opportunities to lead by example here, including by reducing energy use in public buildings and fleets, and by enabling the market for energy service companies (ESCOs) that finance and deliver energy-saving projects. States can also fund research centers that focus on energy-efficient technology breakthroughs. See Chapter 6 for details.

Examples: New York, Connecticut, Alaska

Explore and promote innovative financing mechanisms to leverage private capital and lower upfront costs of energy efficiency measures. While utilities in many states offer some form of on-bill financing program to promote energy efficiency in homes and buildings, expanding lender and customer participation has been an ongoing challenge. States can help address this challenge by passing legislation, increasing stakeholder awareness, and addressing legal barriers to the implementation of financing programs. A growing number of states are seeking new ways to maximize the impact of public funds and invigorate energy efficiency by attracting private capital through emerging financing models such as PACE and green banks.

Examples: Missouri, New York, Rhode Island

Chapter 2. Utility and Public Benefits Programs and Policies

Authors: Seth Nowak and Weston Berg

INTRODUCTION

The utility sector is critical to implementing energy efficiency. Electric and natural gas utilities and independent statewide program administrators deliver a substantial share of US electricity and natural gas efficiency programs.[6] Utility customers fund these programs through utility rates and statewide public benefits funds. Through these programs, utilities encourage customers to use efficient technologies and thereby reduce their energy waste. Energy efficiency is therefore a resource—one similar to power plants, wind turbines, or solar panels. Driven by regulation from state utility commissions, utilities and program administrators in some states have been delivering energy efficiency programs and market transformation initiatives for decades, offering various efficiency services for residential, commercial, industrial, and low-income customers.[7]

Utilities and administrators implement energy efficiency programs in all 50 states and the District of Columbia. Program approaches include financial incentives, such as rebates and loans; technical services, such as audits, retrofits, and training for architects, engineers, and building owners; behavioral strategies; and educational campaigns about the benefits of energy efficiency improvements. Utilities and administrators also continue to develop new and creative ways of delivering energy efficiency to their customers, including some customer segments that have been more difficult to serve, such as small business and multifamily.

METHODOLOGY

For this chapter, we gathered statewide data on the following:

- Utility energy sales (electricity and natural gas) to customers in 2014 and 2015
- Utility revenues from retail energy sales in 2014 and 2015
- Number of residential natural gas customers in 2014
- Budgets for electricity and natural gas energy efficiency programs in 2015 and 2016
- Actual spending for electricity and natural gas energy efficiency programs in 2014 and 2015
- Incremental net and gross energy electricity and natural gas energy efficiency program savings in 2014 and 2015[8]

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[6] Other major programs, run by state governments, are discussed in Chapter 6.

[7] For more information on the historical growth of utility energy efficiency programs, see ACEEE's *Three Decades and Counting: A Historical Review and Current Assessment of Electric Utility Energy Efficiency Activity in the States* (York et al. 2012).

[8] Gross savings are those expected from an energy efficiency program, crediting all installed efficiency measures, including those that would have been installed in the absence of the program. Net savings are those attributable to the program, typically calculated by removing free riders (program participants who would have implemented or installed the measures without incentive, or with a lesser incentive). States differ in how they define, measure, and account for free-ridership and other components of the net savings calculation (Haeri and Khawaja 2012).

- Policies and regulations to encourage utility investment in energy efficiency
- Utility policies and programs related to large customers, including self-direct and opt-out provisions
- Data access policies and provisions[9]

Our data sources included information requests completed by state utility commissions, the Consortium for Energy Efficiency (CEE 2012–2016),[10] EIA (EIA 2015, 2016a, 2016b, 2016c), and regional efficiency groups.[11] We sent the data we gathered, including last year's *State Scorecard* data, to state utility commissions and independent administrators for review. Table 7 shows overall scores for utility programs and policies. Tables 9, 11, 13, and 15 provide data on electricity and natural gas efficiency program savings and spending in the most recent years for which data are available.

SCORING AND RESULTS

This chapter reviews and ranks the states based on their performance in implementing utility-sector efficiency programs and enabling policies that are evidence of states' commitment to energy efficiency. The seven utility scoring metrics are

- Incremental electricity program savings as a percentage of retail sales (7 points)[12]
- Incremental natural gas program savings as a percentage of residential and commercial sales (3 points)
- Electricity program spending as a percentage of statewide electric utility revenues (3 points)
- Natural gas program spending per residential gas customer (2 points)
- Opt-out provisions for large customers (reduction of 1 point)
- EERS for utilities and statewide program administrators (3 points)
- Utility business models that encourage energy efficiency, including performance incentives and mechanisms for addressing lost revenue (2 points)

In this category, a state could earn up to 20 points, or 40% of the 50 total points possible in the *State Scorecard*. We set this point allocation because the savings potential of utility and

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[9] We used these data from state responses to present best practices, not to develop scores.

[10] The Consortium for Energy Efficiency (CEE) surveys administrators of public benefits programs annually to capture trends in aggregated budgets and expenditures. CEE has granted ACEEE permission to reference survey results as of a point in time for the purpose of capturing updates to the budget, expenditure, and impacts data. The full report is at www.cee1.org/annual-industry-reports.

[11] The six regional energy efficiency organizations (REEOs) include the Midwest Energy Efficiency Alliance (MEEA), Northeast Energy Efficiency Partnerships (NEEP), Northwest Energy Efficiency Alliance (NEEA), Southeast Energy Efficiency Alliance (SEEA), South-Central Partnership for Energy Efficiency as a Resource (SPEER), and Southwest Energy Efficiency Project (SWEEP). The REEOs work through funded partnerships with the US Department of Energy and with various stakeholders, such as utilities and advocacy groups, to provide technical assistance to states and municipalities in support of efficiency policy development and program design and implementation.

[12] ACEEE defines incremental savings as new savings from programs implemented in a given year. Incremental savings are distinct from cumulative savings, i.e., the savings in a given program year from all the measures that have been implemented under the programs in that year and in prior years that are still saving energy.

public benefits programs is approximately 40% of the total energy savings potential of all policy areas scored. Studies suggest that electricity programs typically achieve at least three times more primary energy savings than natural gas programs (Eldridge et al. 2009; Geller et al. 2007; Elliott et al. 2007a; Elliott et al. 2007b). Utility-sector potential studies generally indicate significant untapped potential for natural gas efficiency programs (Neubauer 2011; Itron 2006; Mosenthal et al. 2014; GDS 2013; Cadmus 2010). Therefore, we allocated 10 points to performance metrics for electricity programs (annual savings and spending data) and 5 points to performance metrics for natural gas programs (annual savings and spending data). In an effort to award more points to actual energy savings and fewer points to program spending, we shifted a point from spending to savings within the electricity efficiency programs category. To support this change, we refined our data request to improve the accuracy of responses, including accounting for transmission line loss factors for states reporting at the generator level. We also scored states on a variety of enabling policies.

Our scoring methodology for utility sector efficiency savings has had some unintended impacts that we have tried to correct. It disadvantages several states because of the types of energy used or the types of fuels offered to consumers. Hawaii, for example, consumes almost no natural gas (EIA 2016d), so it aims energy efficiency efforts at reducing electricity consumption only. To correct for this issue, we awarded Hawaii the points for natural gas efficiency spending, savings, and regulatory structures equivalent to the proportion of points it earned for corresponding electricity programs and policies. We gave the same treatment to the three US territories included in this report. Elsewhere, particularly in the Northeast, energy efficiency efforts often aim to reduce the consumption of fuel oil. While we capture these efforts in program spending when they are combined with efficiency programs targeting electricity or natural gas, we have not otherwise accounted for fuel oil savings, but will consider ways to do so in future iterations of the *State Scorecard*.[13]

We continue our practice of reporting programs' incremental energy savings (new savings from programs in each program cycle) rather than their cumulative energy savings (savings in a given year from all current and previously implemented energy efficiency measures still saving energy under applicable programs). We report incremental savings in the *State Scorecard* for two reasons. First, basing our scoring on cumulative energy savings would involve levels of complexity that are beyond the scope of the *State Scorecard*, including identifying the start year for the cumulative series and accurately accounting for the life of energy efficiency measures and the persistence of savings. Second, the *State Scorecard* aims to provide a snapshot of states' current energy efficiency programs, and incremental savings give a clearer picture of recent efforts.

This year, we also requested that our contacts at state utility commissions provide both lifetime savings and cumulative savings from electric and gas energy efficiency programs.

[13] In the *2016 State Scorecard* data request distributed to utility commissions, we did ask respondents to provide levels of savings and program expenditures associated with fuel oil savings. Eight states reported data in this category. Given variations in reporting formats among states, we did not include fuel oil savings in this year's *Scorecard* but intend to do so next year.

Cumulative savings are the savings in a given program year from all measures that have been implemented under the program that year and in prior years that are still saving energy. Meanwhile, lifetime savings look ahead to the expected energy savings over the lifetime of an installed measure(s), calculated by multiplying the incremental MWh or therm reduction associated with a measure(s) by the expected lifetime of that measure(s).[14] Although lifecycle savings have the potential to serve as a forward-looking alternative to our current scoring methodology, we did not use these measures for scoring this year, as we did not have data for roughly half of the states.

There are some other possible metrics we do not use for scoring. We do not attempt to include program cost effectiveness or level of spending per unit of energy savings. All states have cost-effectiveness requirements for energy efficiency programs. However the wide diversity of measurement approaches across states makes comparison less than straightforward. Also, several states require program administrators to pursue all cost-effective efficiency. Although some states have prioritized low acquisition costs and encouraged maximizing the *degree* of cost effectiveness, promoting larger *amounts* of marginally cost-effective energy savings is another valid approach. We also do not adjust savings for variations in avoided costs of energy across states, as there are examples of achieving deep energy savings in both high- and low-cost states.

Note that scores are for states as a whole, and therefore may not be representative of the specific efforts of each utility within the state. We do not assess the energy savings performance of individual utilities.[15] A single utility, or small set of utilities, may do very well in terms of energy efficiency programs and associated metrics (spending and savings), but when viewed in combination with all utilities in that state, such efforts can be masked by other utilities not performing as well.

Table 7 lists states' overall utility scoring. Explanations of each metric follow.

[14] EIA refers to this type of data as *incremental life cycle savings*.

[15] ACEEE is currently in the research phase of its inaugural *Utility Scorecard*, anticipated for a 2017 release.

Table 7. Summary of state scores on utility and public benefits programs and policies

State	2015 electricity program savings (7 pts.)	2015 gas program savings (3 pts.)	2015 electricity program spending (3 pts.)	2015 gas program spending (2 pts.)	Opt-out provision (-1 pt.)	Energy efficiency resource standard (3 pts.)	Performance incentives & fixed cost recovery (2 pts.)	Total score (20 pts.)
Rhode Island	7	3	3	2	0	3	2	20
Massachusetts	7	2.5	3	2	0	3	2	19.5
Vermont	7	2.5	3	1.5	0	3	2	19
California	6.5	1.5	2.5	1	0	1.5	2	15
Connecticut	5	1	2.5	2	0	2	2	14.5
Minnesota	3.5	2.5	1.5	1	0	2	2	12.5
Hawaii	5	2	0.5	0.5	0	1.5	2	11.5
Oregon	3.5	2	2.5	1	0	1.5	1	11.5
Arizona	4	2	0.5	0	0	3	1	10.5
Maine	5	0	2	1	-1	3	0.5	10.5
Michigan	3.5	2	1	1	0	1.5	1.5	10.5
New York	3.5	1	1	2	0	1	2	10.5
Washington	4.5	0.5	2.5	0.5	0	1.5	1	10.5
Iowa	3	1.5	2	2	0	1.5	0	10
Maryland	3	0	2.5	0.5	0	2.5	1	9.5
New Hampshire	1.5	2.5	0.5	2	0	1.5	1.5	9.5
Illinois	3.5	1	1.5	1	0	1	0.5	8.5
Wisconsin	2.5	2.5	0.5	0.5	0	1	1	8
Colorado	3	0.5	1	0.5	0	1.5	1	7.5
Arkansas	2	1	1.5	1	-1	1	1.5	7
Utah	2.5	1.5	1.5	1	0	0	0.5	7
Ohio	3	0	0.5	2	-1	0.5	1.5	6.5
District of Columbia	2	0	0.5	1.5	0	0	1.5	5.5
Indiana	2.5	0.5	0.5	0.5	-1	0	1	4
New Jersey	1.5	0.5	1	1	0	0	0	4
New Mexico	1.5	0	1	0.5	0	0.5	0.5	4
Idaho	2	0	1	0	0	0	0.5	3.5
Oklahoma	1	0.5	1	0.5	-1	0	1.5	3.5
Pennsylvania	2	0	0.5	0.5	0	0.5	0	3.5
Kentucky	1	1	0	0.5	-1	0	1.5	3
Nevada	2	0	0.5	0	0	0	0.5	3

State	2015 electricity program savings (7 pts.)	2015 gas program savings (3 pts.)	2015 electricity program spending (3 pts.)	2015 gas program spending (2 pts.)	Opt-out provision (-1 pt.)	Energy efficiency resource standard (3 pts.)	Performance incentives & fixed cost recovery (2 pts.)	Total score (20 pts.)
South Dakota	0.5	0	0	0.5	0	0	1.5	2.5
Alabama	0	0	0	0	0	0	2	2
Missouri	2	0	0.5	0	-1	0	0.5	2
Montana	2	0	0	0	0	0	0	2
North Carolina	2	0	0	0	-1	0	1	2
Georgia	0.5	0	0	0	0	0	1	1.5
Nebraska	1.5	0	0	0	0	0	0	1.5
Delaware	0.5	0	0	0.5	0	0	0	1
Florida	0	0	0	1	0	0	0	1
Mississippi	0.5	0	0	0	0	0	0.5	1
South Carolina	1.5	0	0	0	-1	0	0.5	1
Tennessee	0.5	0	0	0	0	0	0.5	1
Louisiana	0	0	0	0	0	0	0.5	0.5
Wyoming	0	0	0	0	0	0	0.5	0.5
Alaska	0	0	0	0	0	0	0	0
Guam	0	0	0	0	0	0	0	0
Kansas	0	0	0	0	0	0	0	0
North Dakota	0	0	0	0	0	0	0	0
Puerto Rico	0	0	0	0	0	0	0	0
Texas	0.5	0	0	0	-1	0	0.5	0
Virgin Islands	0	0	0	0	0	0	0	0
Virginia	0	0	0	0	-1	0	0.5	-0.5
West Virginia	0.5	0	0	0	-1	0	0	-0.5

DISCUSSION

History of Utility and Public Benefits Programs and Policies

The structure and delivery of customer-funded electric energy efficiency programs have changed dramatically over the past three decades, mostly in conjunction with electric industry restructuring efforts.[16] In the 1980s and 1990s, such programs were almost exclusively the domain of utilities, but efforts in the mid-1990s to restructure and deregulate the electric utilities led numerous states to implement public benefits charges as a new source of funding for efficiency. These public benefits approaches established new structures and tasked utilities—or, in some states, separate efficiency utilities or other third parties—with administering and delivering energy efficiency, renewable energy, and low-income programs.[17]

Despite such public benefits programs, restructuring still resulted in a precipitous decline in funding for customer-funded electricity energy efficiency programs in the late 1990s, primarily due to regulatory uncertainty and the expected loss of cost-recovery mechanisms for those programs.[18] Generally, utilities did not see customer-funded energy efficiency programs as being compatible with competitive retail markets.

After restructuring efforts slowed in some states, utility commissions placed renewed focus and importance on energy efficiency programs. From its low point in 1998, spending for electricity programs increased more than fourfold by 2010, from approximately $900 million to $3.9 billion. In 2015, total spending for electricity efficiency programs reached roughly $6.3 billion. Adding natural gas program spending of $1.4 billion, we estimate total efficiency program spending of approximately $7.7 billion in 2015 (see figure 2).

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[16] By *customer-funded energy efficiency programs*—also known as ratepayer-funded energy efficiency programs—we mean energy efficiency programs funded through charges wrapped into customer rates or appearing as some type of charge on customer utility bills. This includes both utility-administered programs and public benefits programs administered by other entities. We do not include data on separately funded low-income programs, load management programs, or energy efficiency R&D.

[17] States that have established nonutility administration of efficiency programs include Delaware, District of Columbia, Hawaii, Maine, New Jersey, New York, Oregon, Vermont, and Wisconsin.

[18] Under traditional regulatory structures, utilities do not have an economic incentive to help their customers become more energy efficient because their revenues and profits fall in line with falling energy sales due to energy efficiency programs. To address this disincentive, state regulators allow utilities to recover, at a minimum, the costs of running energy efficiency programs through charges on customer bills. For more on this issue, see York and Kushler (2011).

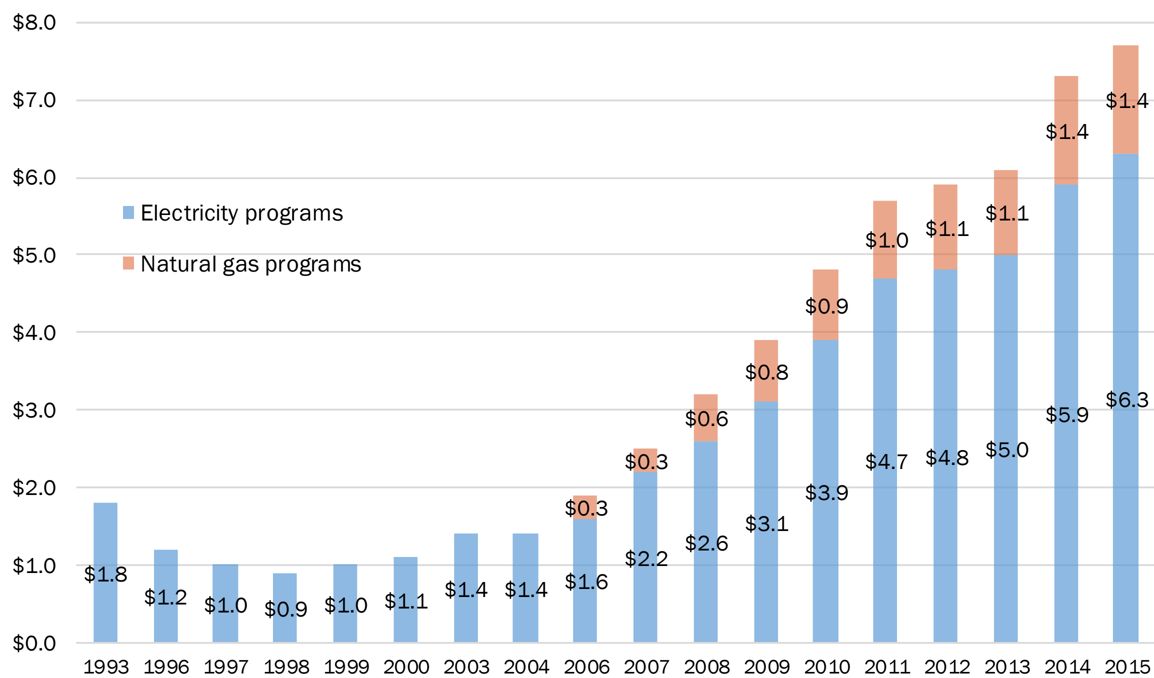

Figure 2. Annual electric and natural gas energy efficiency program spending. Natural gas spending is not available for the years 1993–2004. *Sources:* Nadel, Kubo, and Geller 2000; York and Kushler 2002, 2005; Eldridge et al. 2007, 2008, 2009; CEE 2012, 2013, 2014, 2015; Gilleo et al. 2015.

Given states' increasing commitments to energy efficiency, growth will likely continue over the next decade, but taper off in the long-term due to several factors. These include an anticipated tightening of federal efficiency standards and the fact that many states lack long-range efficiency targets past 2020. One analysis of customer-funded energy efficiency program budgets estimated that funding for electric and natural gas programs will rise to $15.6 billion by 2025 due to the impact of all-cost-effective efficiency policies in leading states, achievement of EERS targets, and peer learning (Barbose et al. 2013). The authors also suggest a regional expansion of the US energy efficiency market, with a large portion of the projected increases in spending coming from states in the Southeast that historically have had relatively low levels of investment.

Furthermore, we expect many states to use energy efficiency as one way to comply with EPA Clean Power Plan (CPP) rules for carbon emissions in existing power plants (EPA 2014a). Even amid the uncertainty prompted by the Supreme Court's stay of the CPP in February 2016, many states have continued to plan for the GHG regulations, albeit with a focus on energy efficiency planning while they await oral arguments scheduled for September before the US Court of Appeals for the District of Columbia Circuit.

Regardless of the court's decision regarding the CPP, energy efficiency will remain a powerful tool to reduce GHG emissions, which the EPA remains required to regulate under the Clean Air Act. ACEEE research finds that energy efficiency policies can yield a 26%

reduction in GHG emissions overall (Hayes et al. 2014).[19] As states plan for carbon emission and other multipollutant reduction requirements over the next several years, it is likely that spending on energy efficiency will continue to rise.

Savings from Electricity and Natural Gas Efficiency Programs

We assess the overall performance of electricity and natural gas energy efficiency programs by the amount of energy saved. Utilities and nonutility program administrators pursue numerous strategies to achieve energy efficiency savings. Program portfolios may initially concentrate on the most cost-effective and easily accessible measure types, such as energy-efficient lighting and appliances. As utilities gain experience, as technologies mature, and as customers become aware of the benefits of energy efficiency, the number of approaches increases. Utilities estimate program energy savings, which are then subject to internal or third-party evaluation, measurement, and verification (EM&V) and are typically reported to the public utility commission on a semiannual or annual basis.

In states ramping up funding in response to aggressive EERS policies, programs typically shift focus from widget-based approaches (e.g., installing new, more efficient water heaters) to more comprehensive deep-savings approaches that seek to generate more energy efficiency savings per program participant by conducting whole-building or system retrofits. Some deep-savings approaches also draw on complementary efficiency efforts, such as utility support for full implementation of building energy codes.[20] Deep-savings approaches may also add to the emphasis on whole-building retrofits and comprehensive changes in systems and operations by including behavioral elements that empower customers.

SCORES FOR INCREMENTAL SAVINGS IN 2015 FROM ELECTRIC EFFICIENCY PROGRAMS

We report 2015 statewide net energy efficiency savings as a percentage of 2015 retail electricity sales and scored the states on a scale of 0 to 7. We awarded up to 6 points last year. Our intention in boosting the number of points for energy savings is to increase our emphasis on actual performance. We relied primarily on states to provide these data. Forty-four states and the District of Columbia completed some or all of our data request form. Where no data for 2015 were available, we used the most recent savings data available, whether from state-reported 2014 savings from the *2015 State Scorecard* or from EIA (2016a, 2016b).

As in 2015, states that achieved savings of at least 2% of electricity sales earned full points. We continue to see examples of states raising the bar beyond 2% electricity savings. In the future, we will consider awarding maximum points only for higher levels of savings (i.e., 2.5%). This year, states that achieved electricity savings of 2% or more in 2015 earned 7 points, with scores decreasing by 0.5 points for every 0.14% decrease in savings.

Table 8 lists the scoring bins for each level of savings.

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[19] This analysis is based on the targets proposed in the draft version of the EPA rule. ACEEE had not yet analyzed final targets during the writing of this report.

[20] See Nowak et al. (2011) for a full discussion of this topic.

Table 8. Scoring of utility and public benefits electricity savings

2015 savings as % of sales	Score
2% or greater	7
1.86–1.99%	6.5
1.72–1.85%	6
1.58–1.71%	5.5
1.44–1.57%	5
1.30–1.43%	4.5
1.16–1.29%	4
1.02–1.15%	3.5
0.88–1.01%	3
0.74–0.87%	2.5
0.60–0.73%	2
0.46–0.59%	1.5
0.32–0.45%	1
0.18–0.31%	0.5
Less than 0.18%	0

Table 9 shows state results and scores. Nationwide reported savings from utility and public benefits electricity programs in 2015 totaled 26.5 million MWh, equivalent to 0.7% of sales.[21] This figure is nearly identical to the savings levels reported last year in this category.

[21] As noted above, 2015 savings were not available in some states at the time of publication. In these cases, we substituted 2014 electricity savings. We have noted these instances in table 9.

Table 9. 2015 net incremental electricity savings by state

State	2015 net incremental savings (MWh)	% of 2015 retail sales	Score (7 pts.)
Rhode Island	222,822	2.91%	7
Massachusetts	1,472,536	2.74%	7
Vermont	110,642	2.01%	7
California†	5,040,603	1.95%	6.5
Maine†	183,347	1.53%	5
Hawaii[1]	144,240	1.52%	5
Connecticut	435,740	1.48%	5
Washington	1,275,447	1.42%	4.5
Arizona†	918,582	1.19%	4
Michigan	1,177,277	1.16%	3.5
Minnesota†	750,672	1.15%	3.5
Illinois	1,553,917	1.13%	3.5
Oregon†	507,502	1.09%	3.5
New York	1,559,665	1.05%	3.5
Maryland	621,090	1.01%	3
Iowa	469,483	1.00%	3
Ohio*†	1,353,109	0.92%	3
Colorado	486,215	0.90%	3
Utah	254,153	0.85%	2.5
Wisconsin	538,678	0.79%	2.5
Indiana[2]	768,927	0.76%	2.5
Nevada†	257,034	0.72%	2
Idaho[3]	159,310	0.69%	2
Montana[4]	92,923	0.66%	2
Pennsylvania*	904,238	0.64%	2
North Carolina	827,508	0.62%	2
Missouri†	494,013	0.61%	2
District of Columbia	69,247	0.61%	2
Arkansas	282,000	0.61%	2
New Hampshire†	64,869	0.59%	1.5
New Mexico	128,834	0.56%	1.5
New Jersey†	409,957	0.55%	1.5
South Carolina[5]	435,399	0.54%	1.5
Nebraska*	156,473	0.53%	1.5
Kentucky	266,522	0.36%	1
Oklahoma	190,497	0.32%	1
Mississippi	144,401	0.29%	0.5
South Dakota	28,686	0.24%	0.5
Georgia†	315,625	0.23%	0.5
Tennessee†	185,355	0.19%	0.5
West Virginia	61,349	0.19%	0.5
Delaware†	21,624	0.19%	0.5
Texas†	698,688	0.18%	0.5
Florida*†	262,085	0.11%	0
Wyoming*†	15,515	0.09%	0
Alabama*†	78,067	0.09%	0
Louisiana	66,695	0.08%	0
Virginia*†	71,182	0.06%	0
North Dakota†	1,663	0.01%	0
Alaska*†	409	0.01%	0
Kansas*†	774	0.00%	0
Guam	—	0.00%	0
Puerto Rico	—	—	0
Virgin Islands	—	0.00%	0
US total	**26,535,588**	**0.71%**	
Median	**255,593**	**0.61%**	

Savings data are from public service commission staff as listed in Appendix A unless noted otherwise. Sales data are from EIA Form 826 (2016c). * For these states, we did not have 2015 savings data, so we scored them on 2014 savings as reported in EIA Form 861 (2016b), unless otherwise noted. [1] 2014 savings as reported in Hawaii data request. [2] 2014 savings as reported in Indiana data request. [3] 2014 savings as reported in Idaho data request. [4] 2014 savings as reported in Montana data request. [5] 2014 savings as reported in South Carolina data request. † At least a portion of savings reported as gross. We adjusted the gross portion by a net-to-gross factor of 0.817 to make it comparable with net savings figures reported by other states.

We scored states on net incremental electricity savings that resulted from energy efficiency programs offered in 2015.[22] We normalized these data by dividing by total electricity sales. Data for electricity sales were based on EIA's *Monthly Electric Utility Sales and Revenue Report with State Distributions* (2016b) and *Annual Electric Power Industry Report* (2016a). Energy savings were based on survey responses from state utility commissions and statewide utility program administrators.

States use different methodologies for estimating energy savings, which can produce inequities when making comparisons.[23] A state's EM&V process plays a key role in determining how savings are quantified. This is particularly true of a state's treatment of free riders (savings attributed to a program that would have occurred anyway in the absence of the program) and spillover (savings *not* attributed to a program that would *not* have occurred without it). States report energy savings as either net or gross, with net savings accounting for free riders and free drivers, and gross savings not accounting for these.[24] The *State Scorecard* specifically focuses on net savings.

In a national survey of evaluation practices, ACEEE researchers found that, of the 45 jurisdictions at the time with formally approved customer-funded energy efficiency programs, 21 jurisdictions reported net savings, 12 reported gross savings, and 9 reported both (Kushler, Nowak, and Witte 2012).[25] These findings point to several important caveats to the electric program savings data. First, a number of states do not estimate or report net savings. In these cases, we have applied a standard factor of approximately 0.817 to convert gross savings to net savings (a net-to-gross ratio).[26] Doing so allows a more straightforward comparison with other states that report net electricity savings. Savings (or some portion of savings) reported as gross are marked by a dagger (†) in table 9.[27] Although Arizona, Minnesota, New Hampshire, and Iowa report gross savings as net to state regulators, we applied the conversion factor to these states because the studies they reference in setting net savings equal to gross savings were outdated or unavailable.

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[22] Incremental electricity savings are new savings achieved from measures implemented in the reporting year. We substituted 2014 data for states that could not report 2015 savings data. Readers should also note that programs that have been running for several years at a high level of funding are achieving the highest levels of *cumulative* electricity savings (total energy savings achieved to date from efficiency measures). *Incremental* savings data, which measure new savings achieved in the current program year, are the best way to directly compare state efforts due to the difficulty in tracking the duration of programs and their savings.

[23] See Sciortino et al. (2011).

[24] *Free drivers* are utility customers who install energy efficiency measures as a result of a program but are not themselves participants in the energy efficiency program.

[25] This includes 44 states and the District of Columbia. Three states did not respond to this question.

[26] We based the 0.817 net-to-gross factor used this year on the median net-to-gross ratio calculated from those states that reported figures for both net and gross savings in this year's data request. These included California, Connecticut, Maryland, New Mexico, New York, North Carolina, Oklahoma, Oregon, Rhode Island, Utah, West Virginia, and Wisconsin. We applied this conversion factor to all states reporting only gross savings and those whose net-to-gross ratios were outliers, falling more than 20% above or below the median. California was the only state that reported a net-to-gross ratio more than 20% below the median.

[27] Savings were determined to be gross based on Kushler, Nowak, and Witte (2012) and on responses to our survey of public utility commissions.

Scores for Incremental Savings in 2015 from Natural Gas Efficiency Programs

Utilities are increasing the number and size of natural gas programs in their portfolios. However data on savings resulting from these programs are still limited. In this category, we awarded points to states that were able to track savings from their natural gas efficiency programs and that realized savings of at least 0.2% as a percentage of sales in the residential and commercial sectors. We relied on data from state utility commissions. Table 10 lists scoring criteria for natural gas program savings. This year, we raised the thresholds and increased the available points for natural gas savings, from our previous maximum of 2 points for savings of 1% of sales or greater up to 3 points for savings equal to or exceeding 1.2% of sales.

Table 10. Scoring of natural gas program savings

Natural gas savings as % of sales	Score
1.20% or greater	3
1.00–1.19%	2.5
0.80–0.99%	2.0
0.60–0.79%	1.5
0.40–0.59%	1
0.20–0.39%	0.5
Less than 0.20%	0

Table 11 shows states' scores for natural gas program savings.

Table 11. State scores for 2015 natural gas efficiency program savings

State	2015 net incremental gas savings (MMTherms)	% of commercial and residential retail sales	Score (3 pts.)
Rhode Island	4.20	1.24%	3
New Hampshire†	1.99	1.12%	2.5
Massachusetts	26.25	1.09%	2.5
Minnesota†	28.92	1.09%	2.5
Wisconsin	28.70	1.08%	2.5
Vermont	0.90	1.01%	2.5
Oregon	6.70	0.93%	2
Arizona	5.65	0.87%	2
Michigan	45.81	0.82%	2
Hawaii**	0.00	0.00%	2
California	49.30	0.75%	1.5
Iowa†	10.39	0.75%	1.5
Utah	7.60	0.73%	1.5
Connecticut	5.70	0.54%	1
Arkansas	4.80	0.52%	1
Illinois	35.40	0.47%	1
New York	36.90	0.46%	1
Kentucky	4.30	0.43%	1
Washington*	4.85	0.35%	0.5
Indiana†	8.90	0.35%	0.5
Colorado	6.69	0.34%	0.5
Oklahoma	3.65	0.30%	0.5
New Jersey†	9.67	0.21%	0.5
District of Columbia	0.60	0.18%	0
Maine†	0.17	0.14%	0
Mississippi	0.70	0.13%	0
New Mexico	0.75	0.13%	0
South Dakota	0.30	0.11%	0

State	2015 net incremental gas savings (MMTherms)	% of commercial and residential retail sales	Score (3 pts.)
North Carolina	1.50	0.11%	0
Maryland	1.40	0.08%	0
Missouri	1.30	0.07%	0
Nevada	0.20	0.03%	0
Pennsylvania	1.00	0.02%	0
Delaware†	0.03	0.01%	0
Alabama	0.00	0.00%	0
Alaska	0.00	0.00%	0
Florida	0.00	0.00%	0
Georgia	0.00	0.00%	0
Guam	0.00	0.00%	0
Idaho	0.00	0.00%	0
Kansas	0.00	0.00%	0
Louisiana	0.00	0.00%	0
Montana	0.00	0.00%	0
Nebraska	0.00	0.00%	0
North Dakota	0.00	0.00%	0
Ohio	0.00	0.00%	0
Puerto Rico	0.00	0.00%	0
South Carolina	0.00	0.00%	0
Tennessee	0.00	0.00%	0
Texas	0.00	0.00%	0
Virgin Islands	0.00	0.00%	0
Virginia	0.00	0.00%	0
West Virginia	0.00	0.00%	0
Wyoming	0.00	0.00%	0
US total	**345.22**	**0.39%**	
Median	**0.90**	**0.13%**	

Savings data were reported by contacts at public utility commissions as listed in Appendix A unless otherwise noted. All sales data are from EIA Form 176 (2015). States that did not report natural gas savings for 2014 or 2015, and for which data were not available elsewhere, were treated as having no savings. * These states did not report 2015 savings and were scored on 2014 savings as reported by public utility commission contacts. ** Hawaii and the US territories use limited natural gas and therefore earn points commensurate with electric efficiency savings scores. † At least a portion of savings reported as gross. We adjusted the gross portion by a net-to-gross factor of 0.864 to make it more comparable with net savings figures reported by other states.

Electricity and Natural Gas Efficiency Program Funding

In this category, we scored states on 2015 electricity efficiency program spending for customer-funded energy efficiency programs. These programs are funded through charges included in utility customers' bills. Our data include spending by investor-owned, municipal, and cooperative utilities, public power companies or authorities, and public benefits program administrators. We did not collect data on the federal Weatherization Assistance Program, which gives money to states on a formula basis. We did include revenues from the Regional Greenhouse Gas Initiative (RGGI), which contribute to customer-funded energy efficiency program portfolios of member states and to energy efficiency programs funded through AB32 and Proposition 39 in California.[28] Where RGGI funds were channeled to energy efficiency initiatives implemented by state governments, we included them in Chapter 6, "State Government–Led Initiatives."

This year, we continue to report energy efficiency spending data rather than energy efficiency *budgets*—an important change we made in 2015 to more accurately capture state energy efficiency funding.[29] For the nine states that did not provide data for 2015 spending on energy efficiency programs for electric or natural gas utilities, we used 2014 spending data from CEE (2016) or data supplied by our state contacts in their 2015 utility data request responses.

Please note that spending data are subject to variation across states, which poses an ongoing challenge to equitably score states based on a common and reliable metric. Several states report performance incentives paid to utilities or other program administrators as part of utility efficiency program spending, resulting in higher spending numbers. While most performance incentives are based on shared net benefits—viewed as an expense—the relative amounts of the incentives are in the range of 5–15% of program spending (Nowak et al. 2015). For this reason, this year we asked states to disaggregate program spending from these incentives. We did not credit this spending in our scoring this year in an effort to more accurately reflect funds directly dedicated to energy efficiency measures. As in past years, we sent spending data gathered from the above sources to state utility commissions for review. Tables 13 and 15 below report electricity and natural gas efficiency program spending, respectively.

SCORES FOR ELECTRIC PROGRAM SPENDING

States could receive up to 3 points based on energy efficiency spending as a percentage of 2015 electric utility revenues.[30] Spending representing at least 4.0% of revenues earned the maximum of 3 points, while spending between 3.0% and 4.0% qualified for 2.5 points. For

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[28] AB32 is California's GHG reduction bill that resulted in a cap-and-trade program. Proposition 39 grants significant funding to energy efficiency programs targeting schools. Both programs are subject to evaluation, measurement, and verification at least as stringent as utility programs.

[29] Prior to 2010, we depended on EIA for actual spending data, which entailed a two-year time lag.

[30] Statewide revenues are from EIA Form 826 (EIA 2016c). We measure spending as a percentage of revenues to normalize the level of energy efficiency spending. Blending utility revenues from all customer classes gives a more accurate measure of utilities' overall spending on energy efficiency than does expressing budgets per capita, which might skew the data for utilities that have a few very large customers. An alternative metric, statewide electric energy efficiency spending per capita is presented in Appendix B.

every 0.5% less than 3%, a state's score decreased by 0.5 points. Table 12 lists the scoring bins for each spending level.

Table 12. Scoring of electric efficiency program spending

2015 spending as % of revenues	Score
4.00% or greater	3
3.00–3.99%	2.5
2.50–2.99%	2
2.00–2.49%	1.5
1.50–1.99%	1
1.00–1.49%	0.5
Less than 1.00%	0

Table 13 shows state-by-state results and scores for this category.

Table 13. 2015 electric efficiency program spending by state

State	2015 spending ($million)	% of statewide electricity revenues	Score (3 pts.)
Vermont	54.4	6.89%	3
Rhode Island	82.9	6.34%	3
Massachusetts	557.9	6.16%	3
Washington	256.9	3.87%	2.5
Maryland	276.8	3.69%	2.5
Oregon	142.9	3.45%	2.5
California	1378.2	3.43%	2.5
Connecticut	173.9	3.32%	2.5
Iowa	113.3	2.86%	2
Maine	42.5	2.74%	2
Minnesota	151.5	2.40%	1.5
Illinois	286.4	2.24%	1.5
Utah	55.9	2.17%	1.5
Arkansas	76.1	2.01%	1.5
Idaho[1]	32.7	1.75%	1
Michigan	188.0	1.70%	1
New Jersey	177.6	1.70%	1
New York	375.7	1.66%	1
Colorado	87.6	1.65%	1
New Mexico	34.3	1.54%	1
Oklahoma	70.2	1.50%	1
New Hampshire	25.6	1.45%	0.5
Pennsylvania	217.2	1.43%	0.5
Missouri	102.3	1.37%	0.5
Hawaii*	33.3	1.34%	0.5
Nevada	45.4	1.34%	0.5
Arizona	105.0	1.31%	0.5
Indiana*	111.7	1.26%	0.5
Ohio[2]	171.9	1.18%	0.5
Wisconsin	79.8	1.07%	0.5
District of Columbia	13.9	1.01%	0.5
North Carolina	113.7	0.91%	0
Florida*	218.0	0.88%	0
Kentucky	43.2	0.72%	0
Montana	9.0	0.72%	0
Texas[3]	181.7	0.54%	0
Tennessee	48.0	0.53%	0
Nebraska	12.9	0.49%	0
South Carolina	36.5	0.47%	0
South Dakota	5.3	0.47%	0
West Virginia	12.4	0.47%	0
Wyoming[4]	5.1	0.38%	0
Mississippi	17.2	0.37%	0
Georgia	41.5	0.32%	0
Delaware	4.0	0.31%	0
Louisiana	13.4	0.20%	0
Alabama[5]	12.2	0.15%	0
North Dakota	0.3	0.02%	0
Virginia[6]	0.1	0.00%	0
Alaska	0.0	0.00%	0
Guam	0.0	0.00%	0
Kansas[7]	0.0	0.00%	0
Puerto Rico	0.0	0.00%	0
Virgin Islands	0.0	0.00%	0
US total	**6,296.4**	-	
Median	**51.2**	**1.28%**	

Statewide revenues are from EIA Form 826 (EIA 2016c). Spending data are from public service commission staff as listed in Appendix A. * Where 2015 spending was not available, we substituted 2014 spending as reported by states, except where noted. [1] 2014 actual spending from CEE 2016 and 2015 BPA spending. [2] 2014 actual spending from CEE 2016. [3] 2015 spending, except for 2014 spending data for CPS Energy and Energy Austin. [4] 2014 actual spending from CEE 2016. [5] 2014 actual spending from CEE 2016. [6] 2014 actual spending from CEE 2016. [7] 2014 actual spending from CEE 2016.

SCORES FOR NATURAL GAS PROGRAM SPENDING

We scored states on natural gas efficiency program spending by awarding up to 2 points based on 2015 program spending data gathered from CEE (2016) and a survey of state utility commissions and independent statewide administrators. To directly compare spending data among the states, we normalized spending by the number of residential natural gas customers in each state in 2015, as reported by the state. When this figure was not available, we relied on 2014 figures from EIA (2015).[31] Table 14 shows scoring bins for natural gas program spending. We awarded states that spent $50 or more per residential customer the full 2 points.

Table 14. Scoring of natural gas utility and public benefits spending

2015 gas spending per customer	Score
$50 or greater	2
$35.00–49.99	1.5
$20.00–34.99	1
$5.00–19.99	0.5
Less than $5.00	0

After seeing a significant uptick in 2014, natural gas program spending levels remained steady at $1.4 billion in 2015, with 19 states spending more than $20 per residential customer. However natural gas efficiency spending remained significantly lower than spending for electricity energy efficiency programs. Table 15 shows states' scores.

[31] We use spending per residential customer for natural gas because reliable natural gas revenue data are sparse, and use of per capita data unfairly penalizes states that offer natural gas service to only a portion of their population (such as Vermont). State data on the number of residential customers are from EIA (2015).

Table 15. 2015 natural gas efficiency program spending by state

State	2015 gas spending ($million)	$ per 2015 residential customer	Score (2 pts.)
Massachusetts	185.5	$127.18	2
Rhode Island	20.1	$84.48	2
Connecticut	37.8	$68.47	2
Ohio*	43.1	$64.84	2
New Hampshire	6.6	$63.98	2
Iowa	54.7	$60.70	2
New York	195.5	$55.81	2
Vermont	2.2	$49.76	1.5
District of Columbia	4.8	$37.21	1.5
Minnesota	50.7	$34.41	1
California	337.3	$32.51	1
Oregon	22.0	$30.80	1
Florida*	20.6	$29.95	1
New Jersey	83.3	$28.08	1
Utah	24.2	$27.44	1
Michigan	74.6	$24.98	1
Illinois	79.7	$23.08	1
Arkansas	12.3	$22.51	1
Maine	0.6	$22.18	1
Washington	21.1	$18.88	0.5
Oklahoma	13.2	$15.35	0.5
Maryland	15.8	$14.18	0.5
Indiana	20.3	$12.55	0.5
Wisconsin	19.9	$11.67	0.5
Colorado	15.1	$8.91	0.5
Delaware	1.3	$8.20	0.5
South Dakota	1.3	$7.26	0.5
New Mexico	3.7	$7.17	0.5
Kentucky	4.9	$6.66	0.5
Pennsylvania	12.7	$5.37	0.5
Hawaii†	0.0	$0.00	0.5
Nevada	4.2	$4.84	0
Missouri	4.9	$3.89	0
Mississippi	1.5	$3.76	0
Virginia*	2.8	$2.52	0
Arizona[1]	2.8	$2.39	0
North Carolina	2.2	$1.84	0
Wyoming*	0.1	$0.89	0
Texas*	2.9	$0.65	0
South Carolina*	0.3	$0.53	0
Montana*	0.1	$0.25	0
Idaho*	0.0	$0.12	0
Alabama	0.0	$0.00	0
Alaska	0.0	$0.00	0
Georgia	0.0	$0.00	0
Guam†	0.0	-	0
Kansas	0.0	$0.00	0
Louisiana	0.0	$0.00	0
Nebraska	0.0	$0.00	0
North Dakota	0.0	$0.00	0
Puerto Rico†	0.0	$0.00	0
Tennessee	0.0	$0.00	0
Virgin Islands†	0.0	$0.00	0
West Virginia	0.0	$0.00	0
US total	**1,406.7**	-	
Median	**4.0**	**$7.22**	

Spending data are from public service commission staff as listed in Appendix A unless noted otherwise. * Where 2015 spending data were not available, we substituted 2014 actual spending as reported by CEE 2016 or by public service commission staff. † Hawaii is awarded points commensurate with points received for electricity spending. [1] Includes 2015 figures for UNS Gas and 2014 figures for Southwest Gas.

Opt-Out Provisions for Large Customers

For the third year running, we assessed opt-out and self-direct provisions for large customers in the *State Scorecard*. Increasingly, large customers are seeking to opt out of utility energy efficiency programs, asserting that they have already done all the energy efficiency that is cost effective. However this is seldom the case (Chittum 2011).

Opt-out policies have several negative consequences. Failure to include large customer programs in an energy efficiency portfolio increases the cost of energy savings for all customers and reduces the benefits. In effect, allowing the large customers to opt out forces other consumers to subsidize them. It also prevents utilities from capturing all highly cost-effective energy savings; this can contribute to higher overall system costs through the use of more expensive supply resources. While the ideal solution is for utilities to offer programs that respond to the needs of these large consumers, ACEEE's research suggests that this does not always happen (Chittum 2011). When it does not, we suggest giving these customers the option of self-directing their energy efficiency program dollars.[32] This option provides a path for including large customer energy efficiency in the state's portfolio of savings, while encouraging utilities to improve program offerings to better respond to all customers' needs. We provide examples of self-direct programs in Appendix C.

SCORES FOR LARGE CUSTOMER OPT-OUT PROVISIONS

This year, we again included opt-out as a category in which states may lose rather than gain points. We subtracted 1 point for states that allow electric or natural gas customers, or both, to opt out of energy efficiency programs.[33]

We did not subtract points for self-direct programs. When implemented properly, these programs can effectively meet the needs of large customers. Self-direct programs vary from state to state, with some requiring more stringent measurement and verification of energy savings than others (Chittum 2011). In the future, we may examine these programs with a more critical eye and subtract points from states that lack strong evaluation and measurement. Table 16 shows states with opt-out programs.

[32] Self-direct programs allow some customers, usually large industrial or commercial ones, to self-direct energy efficiency fees usually paid on utility bills directly into energy efficiency investments in their own facilities instead of into a broader, aggregated pool of funds. These programs should be designed to include comparable methods to verify and measure investments and energy savings.

[33] By default, most large gas customers already are opted out because they take wholesale delivery (frequently directly from transmission) and are thus outside the purview of state government. We did not subtract points in these cases.

Table 16. Provisions allowing large customers to opt out of energy efficiency programs

State	Opt-out description	Score
Arkansas	Customers with more than 1 MW or 70,000 therms in monthly demand may opt out. Only nonmanufacturing customers must offer documentation of similar planned or achieved savings. A significant percentage of eligible load has opted out, although it varies by utility.	–1
Indiana	The opt-out applies to the five investor-owned electric utilities. Eligible customers are those that operate a single site with at least one meter constituting more than 1 MW demand for any one billing period within the previous 12 months. Documentation is not required. No evaluation is conducted. Approximately 70–80% of eligible load has opted out.	–1
Kentucky	Opt-out is statewide for the industrial rate class. Documentation is not required. Approximately 80% of eligible load has opted out, with the remaining 20% made up primarily of TVA customers.	–1
Maine	Large customers that take transmission and subtransmission service are automatically opted out of Maine's efficiency programming. These customers do not pay into Maine's cost-recovery mechanism programming. However federal stimulus funds and money collected from the RGGI have allowed Efficiency Maine to offer energy efficiency programming to the state's largest industrial customers. At the same time, this year's passage of LD 1398 has weakened this effort, increasing the amount of RGGI funds returned to business ratepayers from 15% to 55%.	–1
Missouri	Opt out is statewide for only electric investor-owned utilities. Eligibility requires one account greater than 5 MW, or aggregate accounts greater than 2.5 MW and demonstration of its own demand-side savings. Also, interstate pipeline pumping stations, regardless of size, are eligible. To maintain opt-out status, documentation is required for customers whose aggregate accounts are greater than 2.5 MW. The staff of the Missouri Public Service Commission perform a desk audit of all claimed savings and may perform a field audit. No additional EM&V required.	–1
North Carolina	All industrial-class electric customers are eligible for opt out. Also, by Commission Rule R8-68 (d), large commercial class operations with 1 million kWh of annual energy consumption are eligible to opt out. Customers electing to opt out must notify utilities that they have implemented or plan to implement energy efficiency. Opted-out load represents approximately 40–45% of industrial and large commercial load.	–1
Ohio	As of January 2015, Ohio Senate Bill 310 allows certain customers to opt out of energy efficiency programs entirely. Large customers may opt out of a utility's energy efficiency provisions if they receive service above the primary voltage level (e.g., GSU and GT rate schedules). They may opt out if they are a commercial or industrial customer with more than 45 million kWh usage through a meter, or through more than one meter at a single location, for the preceding calendar year. A written request is required to register as a self-assessing purchaser pursuant to section 5727.81 of the Revised Code.	–1
Oklahoma	All transportation-only gas customers are eligible to opt out. For electric utilities, all customers whose aggregate usage, which may include multiple accounts, is equal to or greater than 15,000,000 kWh annually. 90% of eligible customers opt out.	–1

State	Opt-out description	Score
South Carolina	Industrial, manufacturing, or retail commercial customers with 1 million kWh annual usage or greater are eligible to opt out. Self-certification only is required. Approximately 50% of eligible companies opt out, representing roughly 50% of the eligible load.	–1
Texas	In Texas, for-profit customers that take electric service at the transmission level are not allowed to participate in utilities' energy efficiency programming and therefore do not pay for it. Instead, industrial customers develop their own energy efficiency plans if desired and work with third-party providers to implement and finance energy efficiency investments. Although such investments are not measured or monitored, SPEER is developing a voluntary program that would allow these customers to report and verify savings related to their private investments.	–1
Virginia	Certain large customers are exempt from paying for the costs of new energy efficiency programs. Dominion Power customers may qualify by having average demands between 500 kW and 10 MW; customers with more than 10 MW do not participate in the state's energy efficiency programming by law. Once customers opt out, they cannot take advantage of existing programming nor be charged for it. Customers must show that they have already made energy efficiency investments or plan to in the future. Customers must submit measurement and verification reports yearly in support of their opting out of programs funded by a cost-recovery mechanism.	–1
West Virginia	Opt out is developed individually by utilities. Customers with demand of 1 MW or greater may opt out. Participants must document that they have achieved similar/equivalent savings on their own to retain opt-out status. Claims of energy and/or demand reduction are certified to utilities, with future evaluation by the PUC to take place in a later proceeding. The method has not been specified. Twenty large customers have opted out.	–1

Energy Efficiency Resource Standards

Energy efficiency targets for utilities, often called EERS, are critical to encouraging savings over the near and long term. States with an EERS policy in place have shown average energy efficiency spending and savings levels more than three times as high as states without an EERS policy (Molina and Kushler 2015). Twenty-six states now have fully funded EERS policies that establish specific energy savings targets that utilities and program administrators must meet through customer energy efficiency programs. These policies set multiyear targets for electricity or natural gas savings, such as 1% or 2% incremental savings per year or 20% cumulative savings by 2025.[34]

EERS policies differ from state to state, but each is intended to establish a sustainable, long-term role for energy efficiency in the state's overall energy portfolio. ACEEE considers a state to have an EERS if it has a policy in place that

1. Sets clear, long-term (3+ years) targets for electricity or natural gas savings
2. Makes targets mandatory

[34] *Multiyear* is defined as spanning three or more years. EERS policies may set specific targets as a percentage of sales, as specific gigawatt-hour energy savings targets without reference to sales in previous years, or as a percentage of load growth.

3. Includes sufficient funding for full implementation of programs necessary to meet targets

Several states have chosen to enforce all cost-effective efficiency requirements, which call for utilities and program administrators to determine and invest in the maximum amount of cost-effective efficiency feasible. ACEEE considers states with all cost-effective requirements to have EERS policies in place once these policies have led to multiyear savings targets and have also met the rest of the criteria listed above.

EERS policies aim explicitly for quantifiable energy savings, reinforcing the idea that energy efficiency is a utility system resource on par with supply-side resources. These standards also help utility system planners more clearly anticipate and project the impact of energy efficiency programs on utility system loads and resource needs. Energy savings targets are generally set at levels that push efficiency program administrators to achieve higher savings than they otherwise would have, with goals typically based on analysis of the energy efficiency savings potential in the state to ensure that the targets are realistic and achievable. EERS policies maintain strict requirements for cost effectiveness so that efficiency programs are guaranteed to provide overall benefits to customers. These standards help to ensure a long-term commitment to energy efficiency as a resource, building essential customer engagement as well as the workforce and market infrastructure necessary to sustain the high savings levels.[35]

SCORES FOR ENERGY EFFICIENCY RESOURCE STANDARDS

In this category, we credited states that had mandatory savings targets codified in EERS policies. Our research relied on legislation and utility commission dockets.

A state could earn up to 3 points for an EERS policy based on a number of factors. As table 17 shows, we scored states on a sliding 2.5 scale based on the level of savings called for by their electricity savings targets. States could earn an additional 0.5 points if natural gas was included in the savings goals. We also updated our scoring scale to include half-point increments to better reflect and differentiate levels of savings targets.

Some EERS policies contain cost caps that limit spending, thereby reducing the policy's effectiveness. This year, we did not subtract points for the existence of a cost cap, although we do note whether a cost cap is in place in the results table below. Most of the states with these policies in place have found themselves constrained. As a result, regulators have approved lower energy savings targets. In these cases, we score states on the lower savings targets approved by regulators that take the cost cap into account, rather than on the higher legislative targets.

As we did last year, we awarded top points to states with energy savings targets of 2% of sales or greater. Multiple states have proved that long-term savings of more than 2% are feasible and cost effective.

[35] The ACEEE report *Energy Efficiency Resource Standards: A New Progress Report on State Experience* analyzed current trends in EERS implementation and found that most states were meeting or were on track to meet energy savings targets (Downs and Cui 2014).

Table 17. Scoring of energy savings targets

Electricity savings target or current level of savings met	Score
2% or greater	2.5
1.7–1.99%	2
1.4–1.69%	1.5
1.0–1.39%	1
0.5–0.99%	0.5
Less than 0.5%	0

Other considerations	Score
EERS includes natural gas	+0.5

To aid in comparing states, we estimated an average annual savings target over the next five years or the period specified in the policy. For example, Arizona plans to achieve 22% cumulative savings by 2020, so the average incremental savings target is 2.5% per year.

States with pending targets had to be on a clear path toward establishing a binding mechanism to earn points in this category. Examples of a clear path included draft decisions by commissions awaiting approval within six months, or agreements among major stakeholders on targets. States with a pending EERS policy that had not yet established a clear path toward implementation include Utah and Delaware.[36]

See table 18 below for scoring results and Appendix D for full policy details. (As we show later in table 19, two unscored factors can also affect a policy's outcome.) Although some states have cost caps in place that limit the overall spending allowable on energy efficiency, we do not subtract points for these caps. Rather, we score states based on the savings they have determined are achievable within the cost cap's constraints.

Table 18. State scores for energy efficiency resource standards

State	Approx. annual electric savings target (2014–2020)	Cost cap	Natural gas	Score (3 pts.)
Massachusetts	2.9%		•	3
Rhode Island	2.6%		•	3
Arizona	2.5%		•	3
Maine	2.4%		•	3
Vermont	2.1%		•	3
Maryland	2.0%			2.5

[36] Utah has both a legislative goal (House Joint Resolution 9) and a Renewable Portfolio Goal (S.B. 202) that includes energy efficiency savings targets. Neither of these goals has been codified into regulatory language by the Public Service Commission, so they remain advisory, not binding. Delaware passed legislation to create an EERS, but is still developing regulatory targets.

State	Approx. annual electric savings target (2014–2020)	Cost cap	Natural gas	Score (3 pts.)
Connecticut	1.5%		•	2
Minnesota	1.5%		•	2
Washington	1.5%			1.5
Hawaii	1.4%			1.5
Colorado	1.3%		•	1.5
Oregon	1.3%		•	1.5
California	1.2%		•	1.5
Iowa	1.2%		•	1.5
Michigan	1.0%	•	•	1.5
New Hampshire	1.0%		•	1.5
Arkansas	0.9%		•	1
Wisconsin	0.8%	•	•	1
New York[1]	0.7%		•	1
Illinois[2]	0.7%	•	•	1
Pennsylvania	0.8%	•		0.5
New Mexico	0.6%			0.5
Ohio	0.6%			0.5
Nevada	0.4%			0
North Carolina	0.4%			0
Texas	0.1%	•		0

States with voluntary targets are not listed in this table. Targets in states with cost caps reflect the most recent approved savings levels under budget constraints. See Appendix D for details and sources. [1] Reflects targets proposed by utilities under current REV proceeding. [2] Annual savings target as approved under rate cap. Utilities have additional energy efficiency requirements based on an energy efficiency procurement plan through the Illinois Power Agency.

One highlight of 2016 has been the New Hampshire Public Utilities Commission's long-awaited approval of a settlement agreement establishing a statewide EERS targeting overall cumulative savings of 3.1% of electric sales and 2.25% of gas sales by 2020. In addition, since the publication of the *2015 State Energy Efficiency Scorecard*, several other states have extended their policies or adopted new, more stringent savings targets. For example, in January 2016, the Massachusetts Department of Public Utilities approved 2016–2018 Three-Year Energy Efficiency Plans for electric and gas, ramping up savings goals to 2.9% and 1.2%, respectively. Similarly, the Connecticut Department of Energy and Environmental

Protection (DEEP) approved the state's 2016–2018 Electric and Natural Gas Conservation and Load Management Plan in December 2015, increasing electric and gas efficiency targets to 1.51% and 0.61%, respectively. That same month, the Arkansas Public Service Commission issued an order extending the state's 0.9% electricity savings target through 2018, ramping up to 1.00% in 2019, with a natural gas savings target of 0.5% for 2017–2019.

Other states have faced challenges to their EERS policies. In Ohio, an ongoing legislative freeze continued through 2016. With no additional legislative action, savings targets will resume under the original policy in 2017.

New York continues to push ahead on efforts to lay the regulatory foundations for the utility system of the future through its REV proceeding, but concrete energy efficiency targets are still pending. As part of the REV proceeding, the commission carried 2015 electric savings goals for utilities into 2016 and called on utilities to propose targets over the following two years that were at least as high as current savings levels.[37] Because the commission has made it clear that—at least over the next three years—savings targets will continue to be an important and mandatory measure of performance, we continue to give credit for an EERS policy. The New York State Public Service Commission has asked the state's Clean Energy Advisory Council to develop target recommendations by the end of the year.

Long-term energy savings targets require leadership, sustainable funding sources, and institutional support for states to achieve their goals. Several states currently have or in the past have had EERS-like structures in place but have lacked one or more of these enabling elements, and thus have undercut the achievement of their savings goals. States in this situation include Florida and New Jersey, neither of which earned points in this category this year.[38] Most states with EERS policies or other energy savings targets have met their goals and are on track to meet future goals (Downs and Cui 2014).

Utility Business Model and Energy Efficiency: Earning a Return and Fixed Cost Recovery

Under traditional regulatory structures, utilities do not have an economic incentive to promote energy efficiency. They typically have a disincentive, because falling energy sales from energy efficiency programs reduce utilities' revenues and profits—an effect referred to as *lost revenues* or *lost sales*. Because utilities' earnings are usually based on the total amount of capital invested in certain asset categories—such as transmission and distribution infrastructure and power plants—and the amount of electricity sold, the financial incentives are very much tilted in favor of increased electricity sales and expanding supply-side systems.

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[37] The New York Public Service Commission's February 2015 order in the REV case directed that "longer-term goals should exceed existing targets." Utilities have filed plans for the 2016–2018 period with incremental electricity savings ranging from 0.4% to 0.9% of retail sales per year. In January, the PSC also authorized NYSERDA's Clean Energy Fund (CEF) Framework, which outlines a minimum 10-year energy efficiency goal of 10.6 million MWh measured in cumulative first year savings. Some degree of overlap of program savings is anticipated between utility targets and NYSERDA CEF goals.

[38] In 2014, Florida utilities proposed reducing efficiency efforts from 2010 levels by at least 80%. The Florida Public Service Commission approved this proposal. In New Jersey available funds for energy efficiency are far below the amount necessary to meet savings targets laid out by state legislators.

This dynamic has led industry experts to devise ways of addressing the possible loss of earnings and profit from customer energy efficiency programs and thereby remove utilities' financial disincentive to promote energy efficiency. Three key policy approaches properly align utility incentives and remove barriers to energy efficiency. The first is to ensure that utilities can recover the direct costs associated with implementing energy efficiency programs. This is a minimum threshold requirement for utilities and related organizations to fund and offer efficiency programs; every state meets it in some form. Given the wide acceptance of program cost recovery, we do not address it in the *State Scorecard*.

The other two mechanisms are fixed cost recovery (decoupling and lost revenue adjustment mechanisms) and performance incentives. Decoupling—the disassociation of a utility's revenues from its sales—aims to make the utility indifferent to decreases or increases in sales, removing what is known as the *throughput incentive*. Although decoupling does not necessarily make the utility more likely to promote efficiency programs, it removes or reduces the disincentive for it to do so. Additional mechanisms for addressing lost revenues include modifications to customers' rates that permit utilities to collect these revenues, either through a lost-revenue adjustment mechanism (LRAM) or other ratemaking approach. ACEEE prefers the decoupling approach for addressing the throughput incentive and considers LRAM appropriate only as a short-term solution.

Performance incentives are financial incentives that reward utilities (and in some cases nonutility program administrators) for reaching or exceeding specified program goals. These may include a shareholder incentive that is awarded based on achievement of energy savings targets, and an incentive based on spending goals. Of the two, ACEEE recommends shareholder incentives. As table 20 shows, a number of states have enacted mechanisms that align utility incentives with energy efficiency.[39]

SCORES FOR UTILITY BUSINESS MODEL AND ENERGY EFFICIENCY

A state could earn up to 2 points in this category: up to 1 point for having implemented performance incentive mechanisms and up to 1 point for having implemented full revenue decoupling for its electric and natural gas utilities. Table 19 describes the scoring methodology. Information about individual state decoupling policies and financial incentive mechanisms is available on ACEEE's State and Local Policy Database (ACEEE 2016).

[39] For a detailed analysis of performance incentives, see Nowak et al. (2015). For a detailed analysis of LRAM, see Gilleo et al. (2015).

Table 19. Scoring of utility financial incentives

Scoring criteria for addressing fixed cost recovery	Score
Decoupling is in place for at least one major utility, for both electric and natural gas.	1
Decoupling is in place for at least one major utility, either electric or natural gas. There is an LRAM or ratemaking approach for recovery of lost revenues for at least one major utility for both electricity *and* natural gas.	0.5
No decoupling policy has been implemented, although the legislature or commission may have authorized one. An LRAM or ratemaking approach for recovery of lost revenues has been established for a major utility for either electric *or* natural gas.	0
Scoring criteria for performance incentives	**Score**
Performance incentives have been established for a major utility (or statewide independent administrator) for both electric *and* natural gas.	1
Performance incentives have been established for a major utility (or statewide independent administrator) for either electric *or* natural gas.	0.5
Scoring criteria for performance incentives	**Score**
No incentive mechanism has been implemented, although it may have been authorized or recommended by the legislature or commission.	0

This year, 28 states offer a performance incentive for at least one major electric utility, and 19 states have incentives for natural gas energy efficiency programs. Thirty states have addressed disincentives for investment in energy efficiency for electric utilities. Of these, 16 have a lost revenue adjustment mechanism and 16 have implemented decoupling. For natural gas utilities, eight states have implemented an LRAM and 23 have a decoupling mechanism. Table 20 outlines these policies. One state making a positive change from last year is Alabama, which has added decoupling, LRAM, and performance incentives for both electric and natural gas. In North Carolina, Duke Energy Progress was granted a portfolio bonus incentive that covers natural gas as well as electricity, earning the state another half point.

Table 20. Utility efforts to address lost revenues and financial incentives

State	Decoupling or LRAM Electric	Decoupling or LRAM Natural gas	Score (1 pt.)	Performance incentives Electric	Performance incentives Natural gas	Score (1 pt.)	Total score (2 pts.)
Alabama	Yes[1]	Yes[1]	1	Yes	Yes	1	2
California	Yes	Yes	1	Yes	Yes	1	2
Connecticut	Yes	Yes	1	Yes	Yes	1	2
Hawaii*	Yes	-	1	Yes	-	1	2
Massachusetts	Yes	Yes	1	Yes	Yes	1	2
Minnesota	Yes	Yes	1	Yes	Yes	1	2
New York	Yes	Yes	1	Yes	Yes	1	2
Rhode Island	Yes	Yes	1	Yes	Yes	1	2
Vermont	Yes	Yes	1	Yes	Yes	1	2
Arkansas	Yes[2]	Yes[2]	0.5	Yes	Yes	1	1.5
District of Columbia	Yes	No	0.5	Yes	Yes	1	1.5
Kentucky	Yes[2]	Yes[2]	0.5	Yes	Yes	1	1.5
Michigan	No	Yes	0.5	Yes	Yes	1	1.5
New Hampshire	Yes[2]	Yes[2]	0.5	Yes	Yes	1	1.5
Ohio	Yes[1]	No	0.5	Yes	Yes	1	1.5
Oklahoma	Yes[2]	Yes	0.5	Yes	Yes	1	1.5
South Dakota	Yes[2]	Yes[2]	0.5	Yes	Yes	1	1.5
Arizona	Yes[2]	Yes[1]	0.5	Yes	No	0.5	1
Colorado	No	Yes[2]	0	Yes	Yes	1	1
Georgia	No	Yes	0.5	Yes	No	0.5	1
Indiana	Yes[2]	Yes	0.5	Yes	No	0.5	1
Maryland	Yes	Yes	1	No	No	0	1
North Carolina	Yes[2]	Yes	0.5	Yes	No	0.5	1
Oregon	Yes	Yes	1	No	No	0	1
Washington	Yes	Yes	1	No	No	0	1
Wisconsin	No	No	0	Yes	Yes	1	1
Idaho	Yes	No	0.5	No	No	0	0.5
Illinois	No	Yes	0.5	No	No	0	0.5
Louisiana	Yes[2]	No	0	Yes	No	0.5	0.5
Maine	Yes	No	0.5	No	No	0	0.5
Mississippi	Yes[2]	Yes[2]	0.5	No	No	0	0.5
Missouri	Yes[2]	No	0	Yes	No	0.5	0.5
Nevada	Yes[2]	Yes	0.5	No	No	0	0.5
New Mexico	No	No	0	Yes	No	0.5	0.5
South Carolina	Yes[2]	No	0	Yes	No	0.5	0.5
Tennessee	No	Yes	0.5	No	No	0	0.5

State	Decoupling or LRAM Electric	Decoupling or LRAM Natural gas	Score (1 pt.)	Performance incentives Electric	Performance incentives Natural gas	Score (1 pt.)	Total score (2 pts.)
Texas	No	No	0	Yes	No	0.5	0.5
Utah	No	Yes	0.5	No	No	0	0.5
Virginia	No	Yes	0.5	No	No	0	0.5
Wyoming	No	Yes	0.5	No	No	0	0.5
Alaska	No	No	0	No	No	0	0
Delaware	No	No	0	No	No	0	0
Florida	No	No	0	No	No	0	0
Guam	No	-	0	No	-	0	0
Iowa	No	No	0	No	No	0	0
Kansas	Yes[2]	No	0	No	No	0	0
Montana	No	No	0	No	No	0	0
Nebraska	No	No	0	No	No	0	0
New Jersey	No	No	0	No	No	0	0
North Dakota	No	No	0	No	No	0	0
Pennsylvania	No	No	0	No	No	0	0
Puerto Rico	No	-	0	No	-	0	0
Virgin Islands	No	-	0	No	-	0	0
West Virginia	No	No	0	No	No	0	0

*** Hawaii received full points for both gas and electric because it uses minimal amounts of natural gas. [1] Both decoupling and lost revenue adjustment mechanism in place. [2] No decoupling, but lost revenue adjustment mechanism in place.**

ADDITIONAL POLICIES

Data Access

The scope of energy usage data that utilities make available to customers and third parties is an area of growing interest first introduced to the *State Scorecard* in 2015. This year, we posed similar data access-related questions to our contacts at state public service commissions.

Data access can help customers save energy in homes, large buildings, and communities. Giving customers and building owners access to utility consumption information can provide a baseline for comparing future performance and help inform their decisions about investing in energy efficiency. Similarly, it is important to give third parties and entrepreneurs access to customer data so they can give customers in-depth analyses of the cost-effectiveness of energy efficiency products and services, in turn encouraging investment in efficiency by reducing risk. Utilities, public utility commissions, or state legislators can advance access to utility consumption information for customers, building owners, and third parties by providing recommended guidelines or requirements that standardize and streamline data access across a utility territory or state. These guidelines and regulations can also facilitate or require data transmission directly from utilities to third parties with customer permission, while also addressing privacy concerns that may pose barriers to data sharing. One avenue of increased customer acceptance is to educate consumers about the benefits of increased data access.

In addition to providing data to customers, building owners, and third-party service providers, multiple other use cases exist for which state and local governments should facilitate data sharing by working with utilities to clarify conditions and guidelines. For example, California Public Utilities Commission rulemaking recognizes specific use cases for local governments seeking access to aggregate data for use in creating Climate Action Plans; for research institutions seeking anonymous energy consumption data to evaluate energy policies; and for environmental groups seeking customer data regarding energy efficiency measures pre- and post-retrofit.[40]

Although state policies can encourage data sharing, the absence of explicit state policies does not mean utilities cannot act. After all, some utilities consider it simply a customer service obligation to empower consumers with the ability to access and share their energy data in a digital world. Regardless of policy, utilities can still facilitate these relationships. For example, utilities in several states give customers access to their own energy use data through an online portal, offering them the option of releasing it to third parties for greater analysis even without an explicit policy promoting such exchanges in place.

The data requests we distributed to utility commission contacts posed the following questions.

Do utilities provide energy usage data for customers to download in an electronic format such as Green Button? Are they required to do so? Here, we identify those states in which utilities let customers download and access their energy use data in an electronic format, giving them usage information that is often a prerequisite to their investing in energy efficiency. We also identify those states in which utility commissions are going a step further to explicitly require utilities to provide energy use data to customers in a standardized electronic format. Doing so helps to facilitate sharing with third-party energy management services. For example, utilities are increasingly supporting Green Button,[41] a technical standard for exchanging energy usage data, which, as the name suggests, enables customers to download energy usage data by simply clicking on a "green button."

Are guidelines or requirements are in place regarding the process for third-party access to customer energy use data? Such policies remove perceived technical and policy barriers to third-party access, specifically by addressing privacy concerns among consumers and liability concerns among utilities.

[40] California Public Utilities Commission. Decision Adopting Rules to Provide Access to Energy Usage-Related Data While Protecting Privacy of Personal Data. Rulemaking 08-12-2009, May 1, 2014. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M090/K845/90845985.PDF

[41] Green Button comes in two varieties: *Green Button Download My Data*, which allows customers to download their energy use data (and upload it to a third-party application), and *Green Button Connect My Data*, which allows customers to automate the secure transfer of their usage data to third parties.

Are utilities required to provide aggregated energy use data to owners of separately metered commercial or multifamily properties, or to public agencies? If so, what are the terms and details of the requirements? Separately metered buildings make up a significant portion of the built environment in many cities, and thus represent a significant opportunity in which to promote energy efficiency. By having access to whole-building energy data, building owners can benchmark energy consumption and identify opportunities to improve energy efficiency. Unfortunately, when attempting to track energy use data within buildings, owners and operators often encounter privacy-related obstacles related to tenant-occupied spaces, where the tenant is the utility customer of record. Clarifying privacy protection and information-sharing practices through data aggregation requirements can help address these concerns.

Table 21 summarizes the responses to these questions. We did not score states on their responses this year, although we will likely score this metric in the future .[42]

[42] Complete information on data access as reported by states can be found at database.aceee.org.

Table 21. Guidelines and requirements for provision of energy usage data

State	Utilities provide energy usage data for customers to download in an electronic format	Requirement for provision of individual energy use data to customers, in a common electronic format (e.g., Green Button)	Guidelines established regarding process for third-party access to customer energy data	Requirement for provision of individual energy use data to third parties, upon authorization by the customer	Requirement for provision of aggregate data to owners of multitenant buildings	Requirement for provision of aggregate data to public agencies
Alabama	•					
California	•	•	•	•	•	•
Colorado	•	•	•	•	•	
Connecticut	•	•	•			•
District of Columbia	•	•	•	•	•	•
Florida	•					
Georgia	•					
Illinois	•	•	•	•		•
Maine	•	•	•	•		•
Maryland		•	•			
Massachusetts	•					
Michigan	•					
Nevada	•		•			
New Hampshire	•		•			
New Jersey	•					
New York		•			•	
North Dakota	•					
Oklahoma	•		•			
Pennsylvania			•			
Rhode Island	•					
Texas	•	•	•	•		
Vermont	•					
Washington	•					
Wisconsin	•		•			

Complete information on data access policies can be found in the State and Local Policy Database (ACEEE 2016). States that have no policies in place or that did not provide responses are not included in the table.

States that have taken notable steps toward clarifying guidelines for the provision of customer energy usage data are described below.

Leading and Trending States: Data Access

District of Columbia. The Sustainable DC Act of 2014 included a provision that mandates both electric and gas utilities to provide aggregated whole-building data upon request to a building owner, making it the first jurisdiction in the country to do so. These data are then made available for download and through automated upload to ENERGY STAR® Portfolio Manager. Data are aggregated to the whole-building level for five or more accounts, to address any privacy concerns and simplify the process of benchmarking multitenant buildings.

California. In September 2015, California passed Assembly Bill 802 invigorating the state's benchmarking program by increasing transparency and public access to energy data. The bill required utilities to make available whole-building aggregated energy consumption data when requested to by building owners. Meanwhile Green Button Connect My Data continues to gain traction across the state, graduating from earlier limited pilots programs to more widespread adoption by large investor-owned utilities.

Illinois. In March 2016, the Illinois Commerce Commission issued an order directing Commonwealth Edison Company and Ameren to take the first steps to give customers with smart meters the ability to authorize and share their energy usage data with registered third-party companies using Green Button Connect My Data. Commission order 15-0073 establishes the process by which Illinois consumers can obtain and control access to their electricity usage data. Customers of Commonwealth Edison with smart meters can use Green Button Connect My Data as of May 2016. (All customers will have a smart meter by 2018.)

New York. The New York Public Service Commission issued a March 2016 order approving an advanced metering infrastructure (AMI) business plan by ConEd under the condition that the utility both provide Home Area Network (HAN) functionality and implement Green Button Connect My Data. In a subsequent order, utilities with AMI deployment plans were directed to submit a proposed implementation plan, budget, and timeline for implementing Green Button Connect My Data or an alternate standard that offers similar functionality. Utilities without AMI deployment plans were directed to identify other tools that could be used to improve customer and authorized third-party access to customer data in their initial diversified stock income plans.

Texas. Regardless of the utilities that serve them, customers can access their data by registering with the portal smartmetertexas.com. Third parties can also readily gain access to customer data after consent is received to help customers make informed decisions about reducing their energy use. Furthermore, SPEER has published the *Smart Energy Roadmap for Texas*, which details numerous strategies for improving data collection and customers' data access, as well as ways to better inform customers of available savings opportunities.

States across the country continue to ramp up utility-scale energy efficiency efforts. Although many of the traditional leaders remain in this space, states and regions relatively new to energy efficiency are also making notable progress. Several examples are described below.

Leading and Trending States: Utility and Public Benefits Programs and Policies

Arkansas. Arkansas is leading in the Southeast, having significantly ramped up its utility-sector energy efficiency initiatives since 2007. In that year, the Arkansas Public Service Commission (PSC) approved rules for conservation and energy efficiency programs requiring electric and natural gas utilities to administer energy efficiency programs. In 2010, the state adopted an EERS for both electricity and natural gas and established rules for cost recovery, performance incentives, and utility resource planning. In a 2015 PSC Order, these targets were increased to incremental annual savings of 0.9% and 0.5% for electricity and gas, respectively, for 2017–2018, although an opt-out provision may limit future savings. Arkansas is also developing a new financing mechanism for residential utility customers to add more energy efficiency program offerings to the utilities' core programs.

Maine. In Maine, net incremental savings made a sizeable leap, from 1.21% of retail sales in 2014 to 1.69% in 2015. In 2013, the state's Omnibus Energy Act stabilized the process for funding the Efficiency Maine Trust's electricity savings programs and expanded important funding for programs that reduce heating demand and promote alternative heating systems. In FY 2015, the Trust leveraged significant foundational work completed in FY 2014 to implement significant thermal efficiency programs. This past year marked the first full year of the state's new Home Energy Savings Program (HESP) and a significant portion of funds dedicated to new programs in FY 2014 were not fully invested until FY 2015. As Maine enters the final year of its second Triennial Plan, its third Triennial Plan (2017–2019) will target energy savings between 2.2 and 2.6% annually.

Vermont. Vermont pioneered the third-party administration model of implementing energy efficiency programs, which has been replicated in many states, including Maine, New Jersey, Delaware, and Oregon, and the District of Columbia. Efficiency Vermont, the state's "energy efficiency utility," runs programs for a wide range of customers and leads the nation in producing consistent energy savings. Vermont's excellent performance is due largely to a strategic commitment by the Vermont Public Service Board to fund programs at aggressive levels in order to reach new customers and achieve deep savings. The Public Service Board has an optimal mix of policies, including an EERS and performance incentives, to encourage successful programs.

Rhode Island. Rhode Island invests a greater proportion of utility revenues in energy efficiency than any other state due to its requirement that utilities invest in all cost-effective energy efficiency. A recent revision of the state's energy efficiency potential study confirmed that it should continue to strive for electricity savings of more than 2% per year for the next three years. Natural gas targets of at least 1% per year are similarly aggressive. The state's energy efficiency plans are overseen by a stakeholder board with representatives from government agencies, environmental groups, businesses, and consumer advocates.

Chapter 3. Transportation Policies

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INTRODUCTION

Transportation energy use accounts for approximately 28% of overall energy consumption in the United States and is the second biggest consumer of energy after the electric power sector (EIA 2016a). At the federal, state, or local level, a comprehensive approach to transportation energy efficiency must address both individual vehicles and the transportation system as a whole, including its interrelationship with land use policies. In recent years, the federal government has addressed vehicle energy use through joint GHG and fuel economy standards for light- and heavy-duty vehicles. However states have historically led the way in creating policies for other aspects of transportation efficiency.

The energy efficiency score for the transportation category reflects state actions that go beyond federal policies to achieve a more energy-efficient transportation sector. These may be measures to improve the efficiency of vehicles purchased or operated in the state, policies to promote more efficient modes of transportation, or the integration of land use and transportation planning to reduce the need to drive.

SCORING AND RESULTS

While ambitious fuel economy and GHG standards for light-duty vehicles are now in place at the national level through 2025, states continue to play a crucial role in ensuring continuing progress toward high-efficiency vehicles.[43] Consequently, we awarded states that have adopted California's GHG vehicle emissions standards 1 point and those that also adopted its Zero Emission Vehicle (ZEV) program an additional 0.5 points. In addition, we awarded 0.5 points to states with consumer incentives for the purchase of high-efficiency vehicles. States with more than 30 registered EVs per 100,000 people qualified for an additional 0.5 points, while those with more than 70 EVs per 100,000 earned a full point.

States can lead the way in improving not only vehicle fuel efficiency but also the efficiency of transportation systems more broadly. States that have a dedicated transit revenue stream earned 1 point in this year's *State Scorecard*. Twenty-two states have transit statutes in place that provide sustainable funding sources for operating expenses, as well as for transit facility expansion and maintenance. For details, see Appendix G. States also received points based on the magnitude of their transit spending: relatively large investments ($50 per capita or more) received 1 point, while investments ranging from $20 to $50 per capita received 0.5 points. Maryland, for instance, saw a 40% increase in per capita transit spending between fiscal years 2012 and 2013.

Policies that promote compact development and ensure the accessibility of major destinations are essential to reducing transportation energy use in the long term. States with smart growth statutes earned 1 point. These statutes include the creation of zoning overlay

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[43] The light-duty standards finalized by the EPA and DOT in 2012 are up for review in 2017, and states that have adopted California's GHG emissions program can help ensure that the federal standards are not weakened in the midterm evaluation process. California's Zero Emissions Vehicle (ZEV) program, which most of these states have also adopted, is proving to be a major driver of advanced technology vehicles in the light-duty market.

districts such as the Massachusetts Chapter 40R program, as well as various other incentives to encourage sustainable growth. See the ACEEE State and Local Policy Database for further details (ACEEE 2016).

States that adopted reduction targets for VMT or transportation-specific GHG reduction goals statewide were also eligible for 1 point. Only six states earned points in this category. Among them is Vermont, which earned a point for the VMT goals outlined in the Comprehensive Energy Plan adopted in 2011 and updated in 2016. This update sets objectives for 2030, one of which is to hold VMT to 2011 levels, with no increase in growth.

We awarded an additional point to states whose rolling 10-year VMT average fell by 5% or more between 2012 and 2014. A reduction of between 1% and 5% earned 0.5 points. We did not adjust VMT data to account for fluctuations in economic conditions. We also awarded 1 point to states with complete streets statutes, which ensure proper attention to the needs of pedestrians and cyclists in all road projects.

Regarding freight system efficiency, we changed our methodology so that states could earn 1 point only if their state freight plans included energy efficiency performance metrics or freight-specific GHG reduction goals. We awarded 0.5 points to states with plans that describe concrete strategies to improve the overall efficiency of the state freight transport system and improve access to multiple modes of carriage.

Table 23 shows state scores. ACEEE recognizes that variations in the geography and urban/rural composition mean that some states cannot feasibly implement some of the policies mentioned in this chapter. Nevertheless, every state can make additional efforts to reduce their transportation energy use, and this chapter illustrates a number of different approaches. Additional details on state transit funding, transportation policies, and incentives for the purchase of high-efficiency vehicles are included in Appendices E, F, and G.

Table 22. State scores for transportation policies

State	GHG tailpipe emissions standards and ZEV program (1.5 pts.)[1]	EV registrations per 100,000 people (1 pt.)[2]	High-efficiency vehicle consumer incentives (0.5 pts.)[3]	VMT targets/GHG reduction goals (1 pt.)[4]	Average % change in VMT per capita (1 pt.)[5]	Integration of transportation and land use planning (1 pt.)[6]	Complete streets legislation (1 pt.)[7]	Transit funding (1 pt.)[8]	Dedicated transit revenue stream statutes (1 pt.)[9]	Freight system efficiency goals (1 pt.)[10]	Total score (10 pts.)
California	1.5	1	0.5	1	1	1	1	1	1	1	10
Massachusetts	1.5	1	0.5	1	0	1	1	1	1	0.5	8.5
New York	1.5	0.5	0.5	1	1	1	1	1	1	0	8.5
Oregon	1.5	1	0	1	1	1	1	0	1	0.5	8
Washington	1	1	0.5	1	1	1	1	0	1	0.5	8
District of Columbia	1.5	1	0.5	0	1	1	1	1	0	0.5	7.5
Vermont	1.5	1	0	1	1	1	1	0	0	0.5	7
Connecticut	1.5	1	0.5	0	0.5	1	1	1	0	0	6.5
Delaware	1	0.5	0.5	0	1	1	1	1	0	0.5	6.5
Maryland	1.5	1	0.5	0	0.5	1	1	1	0	0	6.5
New Jersey	1.5	0.5	0.5	0	0	1	1	1	0	0.5	6
Rhode Island	1.5	0.5	0.5	0	1	1	1	0.5	0	0	6
Maine	1.5	0	0	0	1	1	1	0	1	0	5.5
Florida	0	0.5	0	0	1	1	1	0	1	0.5	5
Illinois	0	0.5	0	0	0.5	1	1	1	1	0	5
Pennsylvania	1	0	0	0	1	0	1	1	1	0	5
Tennessee	0	0.5	0.5	0	1	1	1	0	1	0	5
Colorado	0	1	0.5	0	1	0	1	0	1	0	4.5
Georgia	0	1	0.5	0	1	0	1	0	1	0	4.5
Hawaii	0	1	0	0	0.5	1	1	0	1	0	4.5
Virginia	0	0.5	0	0	1	1	1	0.5	0.5	0	4.5
Michigan	0	0	0	0	0.5	1	1	0.5	1	0	4
Minnesota	0	0	0	0	0.5	0	1	1	1	0.5	4

State	GHG tailpipe emissions standards and ZEV program (1.5 pts.)[1]	EV registrations per 100,000 people (1 pt.)[2]	High-efficiency vehicle consumer incentives (0.5 pts.)[3]	VMT targets/GHG reduction goals (1 pt.)[4]	Average % change in VMT per capita (1 pt.)[5]	Integration of transportation and land use planning (1 pt.)[6]	Complete streets legislation (1 pt.)[7]	Transit funding (1 pt.)[8]	Dedicated transit revenue stream statutes (1 pt.)[9]	Freight system efficiency goals (1 pt.)[10]	Total score (10 pts.)
North Carolina	0	0	0	0	0.5	1	1	0	1	0	3.5
Arizona	0	0.5	0.5	0	1	1	0	0	0	0	3
Iowa	0	0.5	0	0	0.5	1	0	0	1	0	3
South Carolina	0	0	0.5	0	1	0	1	0	0	0.5	3
West Virginia	0	0	0	0	1	0	1	0	1	0	3
Missouri	0	0.5	0	0	0.5	0	1	0	0	0.5	2.5
Puerto Rico	0	-	0.5	0	0	1	1	0	0	0	2.5
Texas	0	0.5	0	0	1	0	1	0	0	0	2.5
Alaska	0	0	0	0	1	0	0	1	0	0	2
Utah	0	0.5	0.5	0	1	0	0	0	0	0	2
Indiana	0	0	0	0	0	0	1	0	0.5	0	1.5
Louisiana	0	0	0.5	0	0	0	1	0	0	0	1.5
New Hampshire	0	0	0	0	0.5	1	0	0	0	0	1.5
Wisconsin	0	0	0	0	0.5	0	1	0	0	0	1.5
Arkansas	0	0	0	0	0	0	0	0	1	0	1
Idaho	0	0	0	0	1	0	0	0	0	0	1
Kansas	0	0	0	0	0	0	0	0	1	0	1
Kentucky	0	0	0	0	1	0	0	0	0	0	1
Mississippi	0	0	0	0	0	0	1	0	0	0	1
North Dakota	0	0	0	0	0	1	0	0	0	0	1
Oklahoma	0	0	0	0	1	0	0	0	0	0	1
Wyoming	0	0	0	0	1	0	0	0	0	0	1
Guam	0	-	0.5	0	0	0	0	0	0	0	0.5
Montana	0	0.5	0	0	0	0	0	0	0	0	0.5

State	GHG tailpipe emissions standards and ZEV program (1.5 pts.)[1]	EV registrations per 100,000 people (1 pt.)[2]	High-efficiency vehicle consumer incentives (0.5 pts.)[3]	VMT targets/GHG reduction goals (1 pt.)[4]	Average % change in VMT per capita (1 pt.) [5]	Integration of transportation and land use planning (1 pt.)[6]	Complete streets legislation (1 pt.)[7]	Transit funding (1 pt.)[8]	Dedicated transit revenue stream statutes (1 pt.)[9]	Freight system efficiency goals (1 pt.)[10]	Total score (10 pts.)
Nebraska	0	0	0	0	0.5	0	0	0	0	0	0.5
Nevada	0	0.5	0	0	0	0	0	0	0	0	0.5
New Mexico	0	0	0	0	0.5	0	0	0	0	0	0.5
South Dakota	0	0	0	0	0.5	0	0	0	0	0	0.5
Alabama	0	0	0	0	0	0	0	0	0	0	0
Ohio	0	0	0	0	0	0	0	0	0	0	0
US Virgin Islands	0	-	0	0	0	0	0	0	0	0	0

[1] Clean Cars Campaign 2016; C2ES 2016. [2] IHS Automotive Polk 2015; State data requests. [3] DOE 2016a. [4] State legislation. [5] FHWA 2015. [6] State legislation. [7] NCSC 2016. [8] AASHTO 2015. [9] State legislation. [10] State freight plans.

DISCUSSION

Tailpipe Emission Standards and the Zero Emission Vehicle Program

As a longtime leader in vehicle emissions standards, California has been instrumental in prodding the federal government to establish GHG standards that draw new efficiency technologies into the market. The state's success in this role is due in part to auto manufacturers' preference for minimizing the number of distinct regulatory regimes for vehicles. In 2002, California passed the Pavley Bill (Assembly Bill 1493), the first law in the United States to address GHG emissions from vehicles. The law requires the California Air Resources Board to regulate GHGs as part of the California Low Emission Vehicle Program. The GHG reductions from this law will be achieved largely through improved fuel efficiency, making these standards, to a large degree, energy efficiency policies.

In 2010, the EPA and the Department of Transportation (DOT) issued harmonized national standards for fuel economy and GHG emissions for model years 2012–2016. The standards match California's GHG tailpipe standards in stringency and call for fleet-wide average fuel economy of 34.1 miles per gallon (mpg) by 2016. In 2012, the California Air Resources Board adopted new GHG standards for model years 2017–2025. The DOT and EPA subsequently finalized new GHG and fuel economy standards as well, calling for a fleet-wide GHG emissions average of 54.5 mpg by 2025. The three programs are now harmonized. As the federal programs undergo a midterm evaluation between 2016 and 2018, the commitment of California and other states that have adopted California's program to reducing vehicle GHG emissions will be important in maintaining the strength of the standards, because automakers strongly prefer a single, national program. California has also updated its ZEV program, requiring an increase in production of plug-in hybrid, battery electric, and fuel-cell vehicles from 2018–2025. The program requires automakers to produce ZEVs to reduce GHG and criteria pollutant emissions. Manufacturers of passenger cars and light trucks (up to 8,500 pounds) must earn a certain number of ZEV credits by meeting state requirements that outline the number of ZEVs that they must produce and deliver for sale (C2ES 2016).

States may choose to adopt either the federal vehicle emissions standards or California's. Fifteen states and the District of Columbia have adopted California's GHG regulations in recent years, but Arizona and Florida repealed their programs in 2012. The states that continue to honor the California standards include Connecticut, Delaware, the District of Columbia, Maine, Maryland, Massachusetts, New Jersey, New York, Oregon, Pennsylvania, Rhode Island, Vermont, and Washington (Clean Cars Campaign 2016). Nine other states and the District of Columbia have adopted California's ZEV requirements (C2ES 2016).

Electric Vehicle Registrations

As more EVs become available to drivers, states can help remove the barriers to their widespread adoption. In addition to reducing the high up-front costs of these vehicles, states can provide incentives for the construction of the required fueling infrastructure. Additionally, nonfinancial benefits—such as emissions testing exemptions—make it more convenient to own an EV. The total number of EV registrations helps track the successful uptake of electric vehicles in a given state.

Incentives for High-Efficiency Vehicles

High purchase cost is a barrier to the entry of fuel-efficient vehicles into the marketplace because these vehicles contain new, advanced technologies. To encourage consumers to purchase fuel-efficient vehicles, states may offer a number of financial incentives, including tax credits, rebates, and sales tax exemptions. Several states offer tax incentives to purchasers of alternative-fuel vehicles—including those that run on compressed natural gas, ethanol, propane, or electricity—and in some cases to purchasers of hybrid vehicles (electric or hydraulic). Although alternative-fuel vehicles can provide environmental benefits by reducing pollution, they do not necessarily increase fuel efficiency, and we did not include policies to promote their purchase in the *State Scorecard*. However we do include incentives for EVs and hybrids, which do have high fuel efficiency. With the arrival of a wide range of plug-in vehicles in recent years, tax credits for electric and hybrid vehicles are playing an important role in spurring their adoption.

We also did not give credit for incentives for the use of high-occupancy vehicle lanes and preferred parking programs for high-efficiency vehicles, as they promote increased vehicle use and consequently have questionable net energy benefits.

Vehicle Miles Traveled (VMT) Reduction Targets and VMT Growth

Improved vehicle fuel economy will not adequately address energy use in the transportation sector in the long term if growth in total VMT goes unchecked. EIA predicts a 13% increase in light-duty VMT between now and 2030, which is lower than previous EIA estimates but which still outpaces anticipated US population growth (EIA 2016a). Demographic changes, increased availability of services based on information and communications technology, and rising mode shares for public transit, biking, and walking after years of decline could sustain a reduced growth rate in VMT into the future relative to business as usual (Dutzik and Baxandall 2013).

Reducing VMT growth is key to managing transportation energy use. Several states have taken on this challenge by setting VMT reduction targets. Success in achieving these targets requires the coordination of transportation and land use planning.

Integration of Policies for Land Use and Transportation Planning

Sound land use planning is vital to supporting alternatives to driving in the United States. Successful strategies vary among states due to differences in their infrastructure, geography, and political environment; however all states benefit from incorporating core principles of smart growth into their comprehensive plans. Energy-efficient transport integrates transportation and land use policies. For a state to reduce fuel use through transportation system efficiency, it must address land use and transportation considerations simultaneously. Such approaches include measures that encourage the provision of

- Transit-oriented development, including mixed land uses (mix of jobs, stores, and housing) and good street connectivity to make neighborhoods friendly to all modes of transportation
- Areas of compact development
- Convenient modes of transportation that provide alternatives to automobiles
- Centers of activity where popular destinations are close together

Complete Streets Policies

Complete streets policies focus on street connectivity and aim to create safe, easy access to roads for all pedestrians, bicyclists, motorists, and public transportation users. Complete streets foster increased use of alternatives to driving and have a significant impact on a state's fuel consumption. According to the National Complete Streets Coalition, modest increases in biking and walking could save 2.4 billion gallons of fuel annually across the country (NCSC 2012). A complete streets policy directs states' transportation agencies to evaluate and incorporate complete streets principles and tasks transportation planners with ensuring that all roadway infrastructure projects allow for equitable access to and use of those roadways.

State Transit Funding

While states receive some federal funds for public transit, a significant proportion of transit funding comes from state budgets. A state's investment in public transit is a key indicator of its interest in promoting energy-efficient modes of transportation, although realizing the potential for energy savings through transit typically requires land use changes that create denser, more mixed-use communities as well.

Dedicated Transit Revenue Streams

As states find themselves faced with increasingly uncertain federal funding streams and federal transportation policies that remain highway-focused, many have taken the lead in finding dedicated funding sources for long-term public transit expenditures. To generate a sustainable stream of capital and operating funds, a number of states have adopted legislation that identifies specific sources of funding for public transit. For instance, in 2010, New York passed Assembly Bill 8180, which directs certain vehicle registration and renewal fees toward public transportation. This metric lets us track state-level progress that is not represented in the time-lagged state transit funding data described above.

Freight

Many states have freight transportation plans in place. The 2012 federal transportation funding authorization bill, MAP-21, contained a number of new freight provisions. States were eligible for an increased share of federal funding for freight projects that (1) were shown to contribute to the efficient movement of freight and (2) were identified in the state freight plan. Thus, MAP-21 effectively encouraged states to develop and adopt freight plans. However it did not promote saving energy through these plans (MAP-21 2012).

Adopted in 2015, the FAST Act superseded MAP-21, requiring states to develop freight plans that include both immediate and long-range planning activities in order to receive federal funds. Plans must be complete by October 2017. Additionally, FAST creates a separate pot of money for intermodal and rail freight projects. Each state is allowed to set aside up to 10% of federally awarded funds for eligible nonhighway projects (FAST 2015).

These freight plans can be further strengthened by adopting concrete targets or performance measures that establish energy efficiency as a priority for good movement. Such measures will involve tracking and reporting the energy efficiency of freight movement in the state as a whole, and they will encourage the use of energy efficiency as a criterion for selecting or evaluating freight projects. States could formulate these performance targets in terms of gallons per ton-mile of freight moved, for example, and targets should reflect performance across all freight modes. Closely related performance measures—such as grams of GHG emitted per ton-mile of freight—are also eligible for points under this metric.

Leading and Trending States: Transportation Policies

California. California is the clear leader in the transportation sector. As part of its plans to implement AB 32, which requires a 25% reduction of 1990 GHG emission levels by 2020, California has identified several strategies for smart growth and VMT reduction. In 2008, the state passed SB 375, which required the California Air Resources Board to develop regional transportation-specific GHG reduction goals in collaboration with metropolitan planning organizations. The board finalized targets in 2011, recommending a 5–8% reduction in vehicle-associated GHG emissions by 2020 for the state's four largest metropolitan planning organizations. These goals must be reflected in regional transportation plans that create compact, sustainable development across the state and thus reduce VMT growth.

Between 2005 and 2007, California adopted the Goods Management Action Plan (GMAP) emphasizing energy efficiency in goods movement. In 2014, the state created the California Freight Mobility Plan (CFMP), which it structured to address all of the MAP-21 national goals including GHG emissions reductions. On the vehicle efficiency side, California passed AB 118 in 2009, providing a voucher program for the incremental cost of purchasing hybrid medium- and heavy-duty trucks. Vouchers range from $6,000 to $45,000. The state also offers tax rebates of up to $2,500 for light-duty zero-emission EVs and plug-in hybrid EVs on a first-come, first-served basis, effective until 2023.

Massachusetts. Like California, Massachusetts has long been a leader on the transportation front. The state is dedicated to encouraging compact, transit-oriented development through a number of measures. The Massachusetts 40R program provides financial incentives for the use of zoning overlays that promote smart growth development in cities and municipalities. The state also has a GHG reduction target that aims to reduce transportation emissions by 2 million tons by 2020, as well as a comprehensive complete streets statute that incorporates pedestrian and bicycle travel in all road construction projects.

To continue curbing emissions and energy consumption in the transportation sector, Massachusetts adopted the California ZEV program to encourage the adoption of electric vehicles. With approximately 95 electric vehicles registered per 100,000 residents, the state is making steady progress in promoting electric vehicles as a viable option for drivers.

New York. New York has steadily moved up the ranks in recent years through its strong efforts in transportation efficiency. On the vehicle efficiency side, New York signed a 2013 memorandum of understanding with seven other states to put a combined 3.3 million ZEVs on the road by 2025. This action supplements the California low-emission vehicle emissions standards that New York adopted in 2005.

The state has also made a number of changes to improve system efficiency. New York is one of the few states in the nation to have a concrete VMT reduction target. A goal set in 2008 calls for a 10% reduction in 10 years. With one of the highest transit ridership rates in the country, the state passed Assembly Bill 8180 in 2010, directing a portion of vehicle registration and license renewal fees to public transportation. The bill also created the Metropolitan Transit Authority Financial Assistance Fund to support subway, bus, and rail services and capital improvements. In 2011, New York adopted a new complete streets policy aimed at providing accessibility for multiple modes of transport.

Leading and Trending States: Transportation Policies (continued)

Oregon. Oregon has made steady progress toward reducing its fuel consumption and VMT in recent years. In 2011, the state adopted transportation-specific GHG reduction goals for six of its largest metropolitan areas; the goals call for a 17–21% reduction of 2005 levels by 2035. In combination with a stringent growth management act, these new goals have helped move Oregon toward the top of the rankings in this policy area.

The state also passed HB 2186 in 2009, calling for all metropolitan planning organizations to create a GHG emissions task force. These task forces look for alternative land use and transportation planning scenarios to meet community growth needs while reducing GHG emissions across the state. Oregon is also one of the first states to pass legislation for a VMT fee program. In an effort to reduce the overall number of miles driven, this voluntary program charges drivers a 1.5 cent-per-mile fee in lieu of the state's 30 cent-per-gallon gas tax.

Washington. Washington has long been a leader in integrating land use and transportation planning to reduce fuel consumption and VMT. The state introduced the Growth Management Act in 1990 in an early attempt to curb suburban sprawl amid rapid population growth. Washington also has an aggressive VMT reduction target, which calls for a 50% reduction in VMT per capita by 2050 relative to 1990 levels. In 2011, the state passed a complete streets law to encourage walkable, multimodal communities. In 2012, the state legislature adopted House Bill 2660, providing grants to public transit agencies to preserve transit service in the state.

Chapter 4. Building Energy Codes

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INTRODUCTION

Buildings consume 74% of the electricity and 41% of the total energy used in the United States, and they account for 40% of US carbon dioxide emissions (DOE 2012). This makes buildings an essential target for energy savings. However, because buildings have long lifetimes and are not easily retrofitted, encouraging building efficiency measures during construction is a practical way to reduce building energy consumption. Mandatory building energy codes are one way to target energy efficiency by legally requiring a minimum level of energy efficiency for new residential and commercial buildings.

Code Adoption

In 1978, California enacted the first statewide building energy code in its Title 24 Building Standard. Several states (including Florida, New York, Minnesota, Oregon, and Washington) followed with state-developed codes in the 1980s. During the 1980s and 1990s, the International Code Council® (ICC) and its predecessor code development organizations developed the Model Energy Code (MEC), later renamed the International Energy Conservation Code® (IECC). Today, most states use a version of the IECC for their residential buildings.

Many commercial building codes are based on ASHRAE 90.1 standards, jointly developed by ASHRAE and the Illuminating Engineering Society (IES). The IECC commercial building provisions include prescriptive and performance requirements that largely coincide with ASHRAE 90.1 requirements. DOE's most recent analysis of commercial codes found IECC 2015 and ASHRAE 90.1-2013 to be similar in terms of stringency (Zhang et al. 2015).

With the publication of each new edition of the IECC and ASHRAE standards, DOE issues determinations on the codes that ascertain their relative impact when compared with older standards and, if justified, establish the latest iteration as the base code with which all states must comply. Within two years of the final determination, states are required to send letters certifying their compliance, requesting an extension, or explaining their decision not to comply.

The most recent IECC and ASHRAE code versions for which DOE has issued energy-saving determinations are ASHRAE 90.1-2013 and the 2015 IECC standards. DOE determinations for these standards are relatively new, finalized in September 2014 for ASHRAE 90.1-2013 and in June 2015 for the 2015 IECC standard. In 2014 DOE reported that ASHRAE 90.1-2013 generates 7.6% greater site energy savings than ASHRAE 90.1-2010. For the most recent residential code update (from 2012 to 2015), the difference is much smaller. The 2015 IECC achieves about 1% greater site energy savings than the 2012 IECC (DOE 2016b). States are required to file commercial code certification statements with DOE by September 2016 and residential certification statements by June 2017. Stakeholder discussions for the development of the 2018 IECC are ongoing in 2016.

Stimulus funding provided through the DOE State Energy Program under ARRA spurred the majority of states to adopt at least the 2009 IECC and ASHRAE 90.1-2007 standards. ARRA required that each of the 50 states accepting stimulus funding for code implementation and compliance implement a plan to achieve compliance with these codes in 90% of new and renovated residential and commercial building space by 2017.

Code Compliance

Robust implementation and enforcement are necessary to ensure that states will reap the benefits of adopted codes. A support network that includes DOE, the Pacific Northwest National Laboratory (PNNL), the Building Codes Assistance Project (BCAP), and a variety of other local, regional, and national stakeholder groups provides advocacy, technical training, and educational resources in an effort to help states and communities reach their compliance goals.

DOE provides many resources to help guide states in code compliance efforts. In addition to funding compliance activities in many states through grants, DOE provides technical assistance—such as model adoption policies, compliance software, and training modules—through its Building Energy Codes Program. Among its most recent efforts is an ongoing three-year Residential Energy Code Field Study in eight states that seeks to establish baseline energy use and determine the degree to which investment in building energy code education, training, and outreach programs can produce a significant, measurable change in residential building energy savings (DOE 2016d).

BCAP is a nonprofit advocacy organization that works closely with states to facilitate compliance with building codes. With support from the DOE's National Energy Technology Laboratory, BCAP's Compliance Planning Assistance (CPA) program helps states conduct gap analysis reports to assess and address gaps in state energy code infrastructure; it also helps them develop strategic compliance plans that establish targeted near- and long-term actions to achieve full energy code compliance. A variety of methods exist to increase compliance with building codes, many of which are promoted and facilitated by BCAP. Along with the CPA program, BCAP has been working with the National Association of State Energy Officials (NASEO) and the Northwest Energy Efficiency Alliance (NEEA) to promote energy code compliance collaboratives. The collaboratives consist of stakeholders groups that explore how best to promote adoption of and compliance with energy codes, including through education, training, key messaging, and advocacy.

Six regional energy efficiency organizations also work closely and collaboratively within their states, and with each other, to coordinate code-related activities to support adoption and compliance efforts.[44]

In addition to these regional and national efforts, states can take other measures to support code compliance. These include

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[44] The six regional energy efficiency organizations are Northeast Energy Efficiency Partnerships (NEEP), the Southeast Energy Efficiency Alliance (SEEA), the Midwest Energy Efficiency Alliance (MEEA), South-Central Partnership for Energy Efficiency as a Resource (SPEER), the Southwest Energy Efficiency Project (SWEEP), and the Northwest Energy Efficiency Alliance (NEEA). These organizations cover all states except California, Hawaii, and Alaska.

- Providing and supporting training programs and outreach for code compliance in order to increase the number and effectiveness of contractors and code officials that monitor and evaluate compliance
- Conducting a study—preferably every five years—to determine actual rates of energy code compliance, identify compliance patterns, and create protocols for measuring compliance and developing best-practice training programs
- Establishing a system through which utilities are encouraged to support code compliance

Utilities can promote compliance with state and local building codes in a number of ways (Misuriello et al. 2012). Many utilities across the country offer energy efficiency programs that target new construction. In several states that have passed EERS policies, programs have been established that allow utilities to claim savings for code enhancement activities, both for adoption and for compliance. Utilities can fund and administer training and certification programs, assist local jurisdictions with implementing tools that streamline enforcement, provide funding for purchasing diagnostic equipment, and assist with compliance evaluation. They also can combine code compliance efforts with efforts to improve energy efficiency beyond code requirements. To encourage utilities to participate, prudent regulatory mechanisms, such as program cost recovery or shared savings policies, must be in place to compensate them for their efforts.

METHODOLOGY

Our review of state building energy code stringency is based predominantly on publicly available information, such as that provided by the Online Code Environment and Advocacy Network (OCEAN), which maintains maps and state overviews of building energy codes, as well as by the DOE Building Energy Codes Program and the expert knowledge of several individuals who are active in state building energy code policy and evaluation. Because OCEAN and the DOE might not capture very recent code adoptions, we also rely on primary data collection. We distributed a data request to energy offices and knowledgeable officials in each state, requesting information on their efforts to measure and enforce code compliance.

SCORING AND RESULTS

States earned credit on two measures of building energy codes: the stringency of residential and commercial codes, and the level of efforts to support code compliance. We awarded points as follows:

- Code stringency
  - Residential energy code (2 points)
  - Commercial energy code (2 points)
- Code compliance
  - Compliance study (1 point)
  - Other compliance activities (2 points)

As in the 2015 *State Scorecard*, states could earn a maximum of 4 points for stringency and 3 points for compliance. However, given the increasing number of states completing field studies to assess compliance rates, we plan to revise this methodology next year. As we discuss later in the chapter, this revision will support our shifting emphasis on measuring actual performance levels in a given state's building stock.

Table 23 lists states' overall building energy code scores. Last year, only California and Illinois achieved the maximum score of 7 points; this year, those states were joined by five others—Massachusetts, New York, Texas, Vermont, and Washington—that made moves to adopt the most recent codes and ensure compliance. Seven other states achieved scores of 6 or more points due to a combination of stringent energy codes and laudable compliance efforts. Explanations of each metric follow.

Table 23. State scores for building energy codes: stringency and compliance

State	Residential code stringency (2 pts.)	Commercial code stringency (2 pts.)	Compliance study (1 pt.)	Additional compliance activities (2 pts.)	Total score (7 pts.)
California*	2	2	1	2	7
Massachusetts*	2	2	1	2	7
Texas	2	2	1	2	7
Vermont	2	2	1	2	7
Washington	2	2	1	2	7
Illinois	2	2	1	2	7
New York*	2	2	1	2	7
Maryland	2	2	1	1.5	6.5
Michigan*	2	2	1	1.5	6.5
Oregon	1.5	2	1	2	6.5
Alabama*‡1	1	2	1	2	6
District of Columbia†	1.5	2	0.5	2	6
Iowa†	1.5	1.5	1	2	6
Minnesota	1.5	1.5	1	2	6
Connecticut*	1	1.5	1	2	5.5
Florida†	1.5	1.5	1	1.5	5.5
Utah	1.5	2	0.5	1.5	5.5
Delaware*	2	2	0	1.5	5.5
Idaho	1	1.5	1	1.5	5
Kentucky	1	1.5	1	1.5	5
Nebraska	1	1	1	2	5
Rhode Island†	1	1	1	2	5

State	Residential code stringency (2 pts.)	Commercial code stringency (2 pts.)	Compliance study (1 pt.)	Additional compliance activities (2 pts.)	Total score (7 pts.)
Colorado	1	1	1	2	5
Montana	1	1.5	0.5	2	5
Pennsylvania	1	1	1	1.5	4.5
West Virginia	1	1	1	1.5	4.5
Arkansas	1	1	1	1	4
Hawaii	1	2	0	1	4
Nevada[2]	1	1	0	2	4
New Hampshire	1	1	0	2	4
New Jersey*	1.5	2	0	0.5	4
Virginia†	1	1.5	0.5	1	4
North Carolina	1	1.5	1	0.5	4
Wisconsin*	1	2	0.5	0.5	4
Georgia	1	1	1	0.5	3.5
New Mexico‡	1	1	0	1.5	3.5
Guam	1	1	0	1	3
Missouri	0.5	0.5	1	1	3
South Carolina	1	1	0	1	3
Ohio*	1	1.5	0	0.5	3
Arizona	1	1	0	1	3
Maine*‡	0.5	1.5	0	1	3
Tennessee*	1	1.5	0	0.5	3
Louisiana	1	1	0	0.5	2.5
Puerto Rico	1	1	0	0.5	2.5
US Virgin Islands	1	1	0	0.5	2.5
Oklahoma	1	0	0	1	2
Indiana	1	1	0	0	2
Alaska	1	0	0	1	2
Kansas	0.5	0.5	0	0.5	1.5
Mississippi	0	1.5	0	0	1.5
North Dakota	0.5	0.5	0	0	1
Wyoming	0	0	0	1	1
South Dakota	0	0	0	0.5	0.5

* These states have signed or passed legislation requiring compliance with a new iteration of codes effective by August 1, 2017, or their rulemaking processes are far enough along that mandatory compliance is imminent. We award these states full credit commensurate with the degree of code stringency as noted in table 24. † These states indicated they had begun a code adoption process, but were not far enough along in the rulemaking process to indicate a clear and imminent compliance timeline. ‡ These states indicated that they have extended building code adoption cycles. [1] Alabama recently adopted the 2015 IECC for residential buildings; because this code is equivalent to the 2009 IRC, the state receives partial credit for residential stringency. [2] Although Nevada has adopted the 2012 IECC for residential and commercial buildings, only certain localities have actually adopted and begun enforcing these codes. As a result, Nevada receives partial credit for significant local adoption. *Sources:* Stringency scores derived from data request responses (Appendix A), the Building Codes Assistance Project (BCAP 2016), and discussions with code experts, as of September 2016. Compliance and enforcement scores are based on information gathered in surveys of state building energy code contacts. See the ACEEE State and Local Policy Database for more information on state codes and compliance (ACEEE 2016).

DISCUSSION

Stringency

We assigned each state a score of 0 to 2 points each for residential and for commercial building energy codes, with 2 being assigned to the most stringent codes, for a total of 4 possible points for building code stringency. Although the most recent iteration of the residential IECC delivers only slightly more energy savings than the 2012 IECC, we nonetheless awarded full points only to states that have adopted this code because there is value in maintaining a continual code updating and adoption process. For detailed information on building code stringency in each state, visit ACEEE's State and Local Policy Database.

Stimulus funding provided through the DOE State Energy Program under ARRA spurred the majority of states to adopt at least the 2009 IECC and ASHRAE 90.1-2007 standards. ARRA required that each of the 50 states accepting stimulus funding for code implementation and compliance implement a plan to achieve compliance with these codes in 90% of new and renovated residential and commercial building space by 2017.

This year, we updated our stringency scoring methodology for states that have yet to adopt, or demonstrate significant local adoption of, the 2009 IECC and ASHRAE 90.1-2007 codes for residential and commercial construction, respectively. Given ARRA's imminent 2017 deadline for 90% compliance, we did not award points to states with codes less stringent than these standards.

We have not limited *State Scorecard* credit to codes that have already become effective. A handful of states are still in the process of updating their building energy codes, and we awarded full credit (commensurate with the degree of code stringency) to those states that have exhibited progress and show a clear path leading to code adoption and implementation within the next year (by August 1, 2017). In table 23, we asterisked the states with a clear path toward adoption and implementation and awarded them full credit. Other states have begun the process of updating their codes, but have yet to demonstrate a clear path toward adoption with a definitive implementation date. Although we did not award these states full credit, it is important to note that they have begun the process and are moving along. Table 23 denotes these states with a dagger symbol; table 24 offers more details.

We also awarded credit to states that demonstrated significant local adoption of building energy codes, as an alternative to a statewide requirement. Many home-rule states—such as Arizona, Colorado, Kansas, and Missouri—adopt and enforce building energy codes at the local level.[45] We have not developed a quantitative method for comparing the interstate impact of jurisdictional code adoptions, in part because of a lack of consistent data across states. We recognize that our methodology is limited, and we do not intend to dismiss this local progress by assigning a lower score to these states. Within Arizona, for example, 54 of the 100 code-adopting jurisdictions have enacted the IECC 2009 or better, according to the

[45] Home rule decentralizes power, allowing a locality to exercise certain powers of governance within its own administrative area. See database.aceee.org for more information on building codes in home-rule states.

IECC. In Missouri, approximately 100 jurisdictions representing 50% of the state's population have adopted the 2009 or 2012 IECC or equivalent codes, according to a Division of Energy survey. Most home-rule states, however, were unable to report levels of code stringency by jurisdiction. We will continue to consider opportunities to improve our methodology and more accurately reflect measurable progress toward building energy code adoption and enforcement.

Table 24 summarizes our scoring methodology for code stringency.

Table 24. Scoring of state residential and commercial building energy code stringency

Residential building code	Commercial building code	Score (2 pts. each)
Exceeds 2012 IECC or meets or exceeds 2015 IECC	Meets or exceeds 2015 IECC or ASHRAE 90.1-2013 or equivalent	2
Meets 2012 IECC or equivalent, or has significant adoption of 2015 IECC in major jurisdictions	Meets or exceeds 2012 IECC or equivalent or ASHRAE 90.1-2010, or has significant adoption of 2015 IECC or ASHRAE 90.1-2013 in major jurisdictions	1.5
Meets or exceeds 2009 IECC or equivalent, or has significant adoption of 2012 IECC in major jurisdictions	Meets or exceeds 2009 IECC or equivalent or ASHRAE 90.1-2007, or has significant adoption of 2012 IECC or ASHRAE 90.1-2010 in major jurisdictions	1
Has significant adoption of 2009 IECC or equivalent in major jurisdictions	Has significant adoption of 2009 IECC or ASHRAE 90.1-2007 in major jurisdictions	0.5
Has no mandatory state energy code, or code precedes 2009 MEC/IECC	Has no mandatory state energy code, or code precedes ASHRAE 90.1-2007 or equivalent	0

Table 25 shows state-by-state scores for this category. We continue our practice of awarding only partial credit to states that adopt model codes with amendments that weaken the codes' energy savings impact, as we have determined through consultation with subject matter experts. One area of increasing concern is the adoption of building energy code amendments with trade-offs that replace energy efficiency with renewable energy. Such trade-offs may encourage overinvestment in generation and neglect cost-effective, common-sense efficiency measures. Although we have not deducted points for such amendments this year, we plan to revisit this decision in future *State Scorecards*.

Table 25. State scores for code stringency

State	Res. score (2 pts.)	Residential code description	Com. score (2 pts.)	Commercial code description	Total score (4 pts.)
California	2	The 2013 Building Energy Efficiency Standards, effective July 1, 2014, are mandatory statewide and exceed the 2012 IECC standards for residential buildings. The 2016 Standards adopted in June 2015 and effective January 1, 2017, are expected to exceed the 2015 IECC standards for residential buildings.	2	The 2013 Building Energy Efficiency Standards, effective July 1, 2014, are mandatory statewide and exceed ASHRAE/IESNA 90.1-2010 for commercial buildings. The 2016 Building Energy Efficiency Standards, adopted in June 2015 and effective January 1, 2017, are expected to exceed ASHRAE/IESNA 90.1-2013 for commercial buildings.	4
Illinois	2	2015 IECC	2	The commercial provisions of the 2015 IECC or ASHRAE 90.1-2013 Standard are equivalent and acceptable paths to compliance.	4
Maryland	2	2015 IECC	2	2015 IECC	4
Massachusetts	2	2015 IECC with strengthening amendments	2	In the process of adopting the IECC 2015 and ASHRAE standard 90.1-2013 as part of the ninth edition MA building code	4
New York	2	2015 IECC, effective October 3, 2016	2	2015 IECC/ASHRAE 90.1-2013, effective October 3, 2016	4
Texas	2	2015 IRC for single family (effective September 1, 2016) and 2015 IECC for all other residential buildings (effective November 1, 2016)	2	2015 IECC (effective November 1, 2016); ASHRAE 90.1-2013 for state-funded buildings (effective June 1, 2016)	4
Vermont	2	2015 IECC	2	2015 IECC with ASHRAE 90.1-2013 as alternative compliance path	4
Washington	2	2015 IECC	2	2015 IECC/ASHRAE 90.1-2013	4
Delaware	2	2012 IECC; currently reviewing 2015 IECC, with adoption expected by May 2017	2	ASHRAE 90.1-2010; currently reviewing ASHRAE 90.1-2013, with adoption expected by May 2017	4
Michigan	2	2015 IECC (effective February 2016)	2	The state recently approved draft rules with reference to ASHRAE 90.1-2013. New codes are estimated to be effective June 2017.	4
New Jersey	1.5	2015 IECC with a significantly weakening amendment	2	ASHRAE 90.1-2013	3.5
District of Columbia	1.5	The 2013 DC Construction Code references 2012 IECC; DC has begun reviewing 2015 codes.	2	The 2013 DC Construction Code includes not only the 2012 IECC and ASHRAE 90.1-2010, but also the 2012 International Green Construction Code. DC has begun reviewing 2015 codes.	3.5

State	Res. score (2 pts.)	Residential code description	Com. score (2 pts.)	Commercial code description	Total score (4 pts.)
Oregon	1.5	Equivalent to IECC 2012	2	With the commercial building updates incorporated into 2014 OEESC, Oregon's energy code is expected to be within plus or minus 2% of ASHRAE 90.1-2013.	3.5
Utah	1.5	2015 IECC with weakening amendments (effective July 1, 2016)	2	2015 IECC (effective July 1, 2016)	3.5
Alabama	1	2009 IRC. An amended version of the 2015 IECC will take effect October 1, 2016. Several local jurisdictions have adopted the 2015 IECC without the state-adopted amendments.	2	ASHRAE 90.1 2013	3
Florida	1.5	The 5th Edition (2014) Florida Building Code, Energy Conservation consists of the foundation code 2012 IECC and amendments.	1.5	The 5th Edition (2014) Florida Building Code, Energy Conservation consists of the foundation code 2012 IECC and amendments.	3
Hawaii	1	2015 IECC with weakening amendments	2	2015 IECC with weakening amendments	3
Iowa	1.5	2012 IECC with amendments; Iowa is in the process of holding public meetings to adopt the 2015 IECC.	1.5	2012 IECC with reference to ASHRAE 90.1-2010	3
Minnesota	1.5	2012 IECC	1.5	Consistent with ANSI/ASHRAE/IES Standard 90.1-2010 and/or the 2012 IECC	3
Wisconsin	1	Wisconsin Uniform Dwelling Code (UDC), is mandatory for one- and two-family dwellings and incorporates the 2009 IECC with state amendments.	2	The state is reviewing draft rules that reference the 2015 IECC/ASHRAE 90.1-2013. The codes are expected to go into effect in Spring 2017.	3
Connecticut	1	The 2012 IECC with weakening amendments is planned for the fall of 2016.	1.5	The 2012 IECC is planned for the fall of 2016.	2.5
Idaho	1	2012 IECC w/weakening amendments (equivalent to 2009 IECC)	1.5	2012 IECC with reference to ASHRAE 90.1-2010	2.5
Kentucky	1	2009 IECC and 2009 IRC with state amendments	1.5	2012 IECC/ASHRAE 90.1-2010	2.5
Montana	1	2012 code with amendments for residential construction (weakening the requirement for exterior insulation)	1.5	2012 IECC or ASHRAE 90.1-2010	2.5

State	Res. score (2 pts.)	Residential code description	Com. score (2 pts.)	Commercial code description	Total score (4 pts.)
Virginia	1	2012 IECC with weakening amendments; currently reviewing 2015 IECC	1.5	2012 IECC with reference to ASHRAE 90.1-2010; currently reviewing 2015 IECC	2.5
North Carolina	1	2009 IECC	1.5	2009 IECC with amendments, with reference to ASHRAE 90.1-2010	2.5
Ohio	1	2009 IECC	1.5	The state is reviewing draft rules that reference the 2012 IECC/ASHRAE 90.1-2010.	2.5
Tennessee	1	Currently reviewing the 2009 IECC as the statewide standard; anticipates the rules will take effect in the fall of 2016.	1.5	2012 IECC for commercial and state-owned buildings (effective August 4, 2016)	2.5
Nevada	1	Significant local adoption of the 2012 IECC	1	Significant local adoption of the 2012 IECC and ASHRAE 90.1-2010	2
Arkansas	1	2009 IECC	1	2009 IECC	2
Colorado	1	Home-rule state—2003 IECC mandatory only for jurisdictions that have already adopted energy codes, otherwise voluntary. Of all building construction, 95% takes place in jurisdictions that have adopted the 2009 or higher code.	1	Home-rule state—2003 IECC mandatory only for jurisdictions that have already adopted energy codes. Of all building construction, 95% takes place in jurisdictions that have adopted the 2009 or higher code.	2
Georgia	1	2009 IECC	1	ASHRAE 90.1-2007	2
Guam	1	2009 IECC	1	2009 IECC	2
Indiana	1	2009 IECC	1	ASHRAE 90.1-2007	2
Louisiana	1	Residential buildings must meet the 2009 IRC with reference to the 2009 IECC. Multifamily residential buildings of three stories or less must meet the 2012 IRC and the energy provisions of the 2009 IECC. Multifamily residential construction of more than three stories must comply with ASHRAE 90.1-2007.	1	ASHRAE Standard 90.1-2007	2
Nebraska	1	2009 IECC	1	2009 IECC with reference to ASHRAE 90.1-2007	2
New Hampshire	1	2009 IECC	1	2009 IECC with references to ASHRAE 90.1-2007	2
New Mexico	1	2009 IECC with amendments	1	2009 IECC with amendments; ASHRAE 90.1-2007 is acceptable compliance path	2

State	Res. score (2 pts.)	Residential code description	Com. score (2 pts.)	Commercial code description	Total score (4 pts.)
Pennsylvania	1	2009 IECC	1	2009 IECC with reference to ASHRAE 90.1-2007	2
Puerto Rico	1	2009 IECC	1	2009 IECC	2
Rhode Island	1	2012 IECC with weakening amendments	1	2012 IECC with weakening amendments	2
South Carolina	1	2009 IECC	1	2009 IECC with reference to ASHRAE 90.1-2007	2
US Virgin Islands	1	2009 IECC	1	2009 IECC	2
West Virginia	1	2009 IECC	1	ASHRAE 90.1-2007	2
Arizona	1	Significant local adoption of 2012 IECC	1	Significant local adoption of 2012 IECC	2
Maine	0.5	2009 IECC (but only about 60% of state is covered)	1.5	2009 IECC/ASHRAE 90.1-2007; working to adopt ASHRAE 90.1-2013 by October 2016	2
Mississippi	0	No mandatory code	1.5	ASHRAE 90.1-2010	1.5
Oklahoma	1	2009 IRC; State Minimum Building Energy Codes are amended by the OUBCC and adopted by the legislature.	0	2009 ICC/IBC, however, the energy chapter references the 2006 IECC	1
Kansas	0.5	Based on information obtained in a 2013 survey of local jurisdictions and 2011 US Census permit data, it is estimated that almost 60% of residential construction in Kansas is covered by the 2009 IECC or better.	0.5	In April 2007, the 2006 IECC became the applicable standard for new commercial and industrial structures. Jurisdictions in the state are not required to adopt the code. Many jurisdictions have adopted the 2009 or 2012 IECC.	1
Missouri	0.5	No mandatory code; significant adoption of 2009 and 2012 IECC in major jurisdictions	0.5	No mandatory code; significant adoption of 2009 and 2012 IECC in major jurisdictions	1
North Dakota	0.5	No mandatory code; significant local adoption of 2009 IECC	0.5	No mandatory code; significant local adoption of 2009 IECC	1

State	Res. score (2 pts.)	Residential code description	Com. score (2 pts.)	Commercial code description	Total score (4 pts.)
Alaska	1	No mandatory code for new construction; however the state -owned Alaska Housing Finance Corporation requires that projects it is financing meet the state-developed Building Energy Efficiency Standards (BEES). Most new residential construction adheres to BEES, which is based on the 2012 IECC with state-specific weakening amendments.	0	No mandatory code; all public facilities must comply with the thermal and lighting energy standards adopted by the Alaska Department of Transportation and Public Facilities mandated by AS44.42020(a)(14).	1
South Dakota	0	Voluntary statewide minimum code	0	Voluntary statewide minimum code	0
Wyoming	0	No mandatory code, but some jurisdictional adoption. The eight most-populated cities and counties in Wyoming have an energy code that meets or exceeds the IECC 2006 or equivalent.	0	No mandatory code, but some jurisdictional adoption. The eight most-populated cities and counties in Wyoming have an energy code that meets or exceeds the IECC 2006 or equivalent.	0

ARRA's impact on building code adoption shows that federal policy can catalyze tremendous progress at the state level. Although a few states have yet to comply with ARRA requirements, the great majority of new residential and commercial construction across the country is subject to compliance with the ARRA codes. Forty states, the District of Columbia, and the three US territories examined in the *State Scorecard* either have adopted or are on a clear path toward adopting codes at least equivalent to ARRA's for residential and/or commercial buildings. Further, some jurisdictions in most home-rule states—where local entities control adoption—have also adopted codes at least equivalent to ARRA's.

Some states regularly adopt the latest iterations of the IECC and ASHRAE 90.1 code standards as they are determined. However other states have recently considered statutory or regulatory requirements to extend code adoption cycles. States unable to adopt the latest building energy codes will miss out on significant energy savings opportunities. ACEEE considered removing points from states with extended code adoption cycles, but most states do not actually update building codes every three years. We therefore decided not to penalize those with extended cycles. Only a few states have made progress toward adopting the most recent DOE-certified codes (or local equivalents) for either residential or commercial new construction. Hawaii, Illinois, Maryland, New Jersey, New York, Utah, Vermont, and Washington have adopted and begun to enforce the 2015 IECC for both commercial and residential construction.[46] Alabama recently adopted ASHRAE 90.1-2013

[46] Although Hawaii has adopted the 2015 IECC for both residential and commercial buildings, the state included weakening amendments to its residential code. New Jersey has also adopted the 2015 IECC, however,

standards for all commercial buildings and an amended version of the 2015 IECC for residential buildings, and Texas recently adopted ASHRAE 90.1-2013 for all state-funded construction projects. Delaware and Massachusetts are in the process of adopting the 2015 IECC and ASHRAE 90.1-2013 for residential and commercial buildings, and Wisconsin is reviewing the 2015 IECC and ASHRAE 90.1-2013 for commercial buildings. In addition, Michigan adopted the residential 2015 IECC and ASHRAE 90.1-2013. While California has yet to begin enforcing the 2015 codes, they earn full credit for exceeding 2012 residential and commercial codes, which go into effect January 1, 2017.

At the other end of the spectrum, nine states lack mandatory statewide energy codes for new residential and/or commercial construction: Alaska, Colorado, Kansas, Maine, Mississippi, Missouri, North Dakota, South Dakota, and Wyoming. Some of these home-rule states are nonetheless showing high rates of adoption at the jurisdictional level, including Arizona, Colorado, Kansas, and Missouri. We award these states points accordingly.

Compliance

Scoring states on compliance is difficult due to the lack of consistent data on actual compliance rates—and the fact that other efforts taken to measure compliance are largely qualitative. Still, as always, we continue to seek ways to have scores reflect tangible improvements in energy savings.

Last year, we updated our scoring methodology to award more credit to states that have completed compliance studies in the past five years. The reasoning behind this decision was that, as the 2017 deadline for 90% compliance approaches, compliance rates should serve as a reflection of a state's code enforcement efforts. We have employed the same methodology this year, but, with the deadline only months away, readers can expect the *2017 State Scorecard* to utilize a new approach. To motivate states to reach and exceed the 90% compliance goal, ACEEE intends eventually to award credit to states based on not only the publication of compliance studies and their rigor, but also the actual level of compliance they report. For more information on state compliance efforts, visit ACEEE's State and Local Policy Database (ACEEE 2016).

Table 26 shows our scoring methodology for assessing state compliance studies.

amendments to the residential portion of the code weaken air leakage test requirements. These states' scores reflect these weakening amendments.

Table 26. Scoring of state efforts to assess compliance

Compliance study	Score (1 pt.)
Compliance study has been completed in the past five years, follows standardized protocols, and includes a statistically significant sample.	1
Compliance study has been completed in the past five years but does not follow standardized protocols or is not statistically significant.	0.5
No compliance study has been completed in the past five years.	0

Table 27 shows our scoring methodology for additional activities to improve and enforce energy code compliance. A state can earn 0.5 points for each compliance strategy it engaged in during the past year. A total of 2 points is possible.

Table 27. Scoring of efforts to improve and enforce code compliance

Additional metrics for state compliance efforts	Score (2 pts.)
Assessments, gap analysis, or strategic compliance plan	0.5
Stakeholder advisory group or compliance collaborative	0.5
Utility involvement	0.5
Training and outreach	0.5

Although several states have recently completed compliance studies demonstrating 90% or higher compliance rates for residential and/or commercial buildings, we believe the current methodology is a valid approach in the near-term for several reasons.

First, while we plan to award more points in the future to states based on their compliance studies' results, we also want to recognize the enormous value in a state's maintaining a robust policy framework. Such a framework can support ongoing efforts to provide training and education to staff, actively monitor code changes, and provide up-to-date information to stakeholders through strong coordination. Second, we want to avoid inadvertently penalizing states with lower compliance rates under newer or more stringent codes; this would work against the *Scorecard*'s goal of rewarding states operating at the leading edges of energy efficiency. Planning meetings for the *2017 State Scorecard* will seek to address these important methodological questions, as well as others—including how best to compare compliance rates conducted using differing methodologies (e.g. prescriptive versus performance-based) and how to update our data request accordingly.

Table 28 shows how states scored for each compliance metric. Details on state activities in these areas are given in the State and Local Policy Database (ACEEE 2016).

Table 28. State scores for energy code compliance efforts

State	Compliance study (1 pt.)	Gap analysis (0.5 pts)	Stakeholder group (0.5 pts)	Utility involvement (0.5 pts.)	Training (0.5 pts)	Total score (3 pts.)
Alabama	●	●	●	●	●	3
California	●	●	●	●	●	3
Colorado	●	●	●	●	●	3
Connecticut	●	●	●	●	●	3
Illinois	●	●	●	●	●	3
Iowa	●	●	●	●	●	3
Massachusetts	●	●	●	●	●	3
Minnesota	●	●	●	●	●	3
Nebraska	●	●	●	●	●	3
New York	●	●	●	●	●	3
Oregon	●	●	●	●	●	3
Rhode Island	●	●	●	●	●	3
Texas	●	●	●	●	●	3
Vermont	●	●	●	●	●	3
Washington	●	●	●	●	●	3
District of Columbia	○	●	●	●	●	2.5
Florida	●	●	●		●	2.5
Idaho	●	●	●		●	2.5
Kentucky	●	●	●		●	2.5
Maryland	●	●	●		●	2.5
Michigan	●	●		●	●	2.5
Montana	○	●	●	●	●	2.5
Pennsylvania	●	●	●		●	2.5
West Virginia	●	●	●		●	2.5
Arkansas	●	●			●	2
Missouri	●	●	●			2
Nevada		●	●	●	●	2
New Hampshire		●	●	●	●	2
Utah	○		●	●	●	2
Delaware		●	●		●	1.5
Georgia	●				●	1.5
New Mexico		●		●	●	1.5
North Carolina	●				●	1.5

State	Compliance study (1 pt.)	Gap analysis (0.5 pts)	Stakeholder group (0.5 pts)	Utility involvement (0.5 pts.)	Training (0.5 pts)	Total score (3 pts.)
Virginia	○		●		●	1.5
Alaska		●			●	1
Arizona				●	●	1
Guam		●			●	1
Hawaii			●		●	1
Maine			●		●	1
Oklahoma		●			●	1
South Carolina		●			●	1
Wisconsin	○				●	1
Wyoming			●		●	1
Kansas			●			0.5
Louisiana					●	0.5
New Jersey					●	0.5
Ohio		●				0.5
Puerto Rico					●	0.5
South Dakota		●				0.5
Tennessee					●	0.5
US Virgin Islands					●	0.5
Indiana						0
Mississippi						0
North Dakota						0

Data from state responses to data requests (see Appendix A). States receiving half-credit for compliance studies are indicated with an unfilled circle. See State and Local Policy Database (ACEEE 2016) for more details on each activity. * Indicates states for which 2015 survey data were used.

According to our survey results, almost every state in the country made some effort to support code compliance, whether a statewide code is mandatory or not. Nearly every state uses at least one of the strategies for boosting compliance discussed above, and a growing number of states uses many or all of them. For states that did not respond to this year's survey or that provided partial responses, we referred to last year's data to complement or supplement information in some cases. States that received zero points for compliance are those that did not respond to our survey or could not report compliance activities.

For states to attain the ARRA 90% compliance goal, they will have to join utilities and other stakeholders in a concerted effort involving a range of strategies beyond training and outreach. Between now and 2017, and beyond, states should focus on the thorough evaluation and estimation of compliance rates. The number of states that have estimated actual compliance rates is slowly increasing, and several states are in the process of conducting compliance studies with DOE assistance. However only a little more than half the states have completed a compliance study of any type, and few of them follow a standard methodology to measure compliance for both the commercial and the residential sector.

Chapter 5. Combined Heat and Power

Authors: Meegan Kelly and Anna Chittum

Introduction

CHP systems generate electricity and thermal energy in a single integrated system. CHP is more energy efficient than generating electricity and thermal energy separately because heat that is normally wasted in conventional generation is captured as useful energy. That recovered energy can then be used to meet a thermal demand for onsite processes, such as heating or cooling a building or generating steam to run a manufacturing process. CHP systems can save customers money and reduce net emissions. The majority are powered by natural gas, but many are fueled by biomass, biogas, or other types of fossil fuels.

Scoring and Results

States can encourage or discourage CHP in many ways. Financial, technical, policy, and regulatory factors affect the extent to which CHP systems are deployed. Our scoring methodology emphasizes CHP as an energy resource, which we believe is the most important policy driver for increasing the use of highly efficient CHP in the United States.

Our methodology is based on four policy categories:

- Interconnection standards for electrically connecting CHP systems to the grid
- Encouraging CHP as a resource
- Deployment incentives
- Additional supportive policies

The second point, encouraging CHP as a resource, is an umbrella category with the greatest weight. It scores states on activities and policies that actively identify CHP as an energy resource and integrate CHP into system planning and energy resource acquisition efforts. The full scoring methodology is outlined below and described in detail later in this chapter.

A state could earn up to 4 points based on the above categories. We awarded points for:

- The presence and design of interconnection standards (0.5 points)
- The extent to which CHP is identified and encouraged as an energy resource, based on four subcategories:
    - Eligibility of CHP within an energy efficiency resource standard or other similar regulatory requirement (0.5 points)
    - The presence of utility- or program administrator–run CHP programs designed to acquire CHP energy resources (0.5 points)
    - The presence of state-approved production goals or program budgets for acquiring a defined amount of kWh savings from CHP (0.5 points)
    - Access to production incentives, feed-in tariffs, standard offer programs, or other revenue streams linked to CHP system kWh production (0.5 points)
- Deployment incentives—including rebates, grants, and financing—or a net metering standard that applies to CHP (0.5 points)
- Additional supportive policies, including certain streamlined air permitting processes, technical assistance, goals for CHP in critical facilities, resiliency efforts,

and policies that encourage the use of renewable or opportunity fuels in conjunction with CHP (1 point)

We also assessed, but did not score, the number of recent CHP installations in each state and the total CHP capacity installed.

Some states recently adopted new and improved policies or regulations, while others are still in the process of developing or improving them. Generally, we did not give credit for a policy unless a legislative body enacted it or an agency or regulatory body promulgated it as an order. We considered policies in place as of July 2016 and relied on primary and secondary sources for data collection. Primary sources included public utility commission dockets and responses to data requests from state energy offices. Secondary sources included policy databases such as the Database of State Incentives for Renewables and Efficiency (DSIRE 2016) and the EPA's CHP Policies and Incentives Database (EPA 2016).

Table 29 lists each state's total score and its point distribution in each of the above categories. Detailed information on the policies and programs that earned points in each category is available in the CHP section of the online ACEEE State and Local Policy Database (ACEEE 2016).

Table 29. Scores for CHP

		Encouraging CHP as a resource						
State	Intercon-nection (0.5 pts.)	EERS treatment (0.5 pts.)	CHP program (0.5 pts.)	Produc-tion goal (0.5 pts.)	Revenue streams (0.5 pts.)	Deployment incentives (0.5 pts.)	Supportive policies (1 pt.)	Total score (4 pts.)
California	0.5	0.5	0.5	0.5	0.5	0.5	1	4
Maryland	0.5	0.5	0.5	0.5	0.5	0.5	1	4
Massachusetts	0.5	0.5	0.5	0.5	0.5	0.5	1	4
New York	0.5	0.5	0.5	0.5	0	0.5	1	3.5
Rhode Island	0.5	0.5	0.5	0	0.5	0.5	1	3.5
Maine	0.5	0.5	0	0.5	0	0.5	1	3
Connecticut	0.5	0.5	0	0	0	0.5	1	2.5
Minnesota	0.5	0.5	0	0	0	0.5	1	2.5
Oregon	0.5	0.5	0	0	0	0.5	1	2.5
Pennsylvania	0	0.5	0	0	0.5	0.5	1	2.5
Washington	0.5	0.5	0	0	0	0.5	1	2.5
Illinois	0.5	0.5	0	0	0	0	1	2
Vermont	0.5	0.5	0	0	0	0.5	0.5	2
Arizona	0	0.5	0	0	0	0.5	0.5	1.5
Delaware	0.5	0	0	0	0	0.5	0.5	1.5
Iowa	0.5	0	0	0	0	0	1	1.5
Michigan	0.5	0	0	0	0	0	1	1.5

State	Intercon-nection (0.5 pts.)	Encouraging CHP as a resource: EERS treatment (0.5 pts.)	CHP program (0.5 pts.)	Produc-tion goal (0.5 pts.)	Revenue streams (0.5 pts.)	Deployment incentives (0.5 pts.)	Supportive policies (1 pt.)	Total score (4 pts.)
New Jersey	0	0	0	0	0	0.5	1	1.5
New Mexico	0.5	0	0	0	0	0.5	0.5	1.5
Ohio	0.5	0.5	0	0	0	0.5	0	1.5
Texas	0.5	0	0	0	0	0	1	1.5
Wisconsin	0.5	0	0	0	0	0	1	1.5
Alaska	0	0	0	0	0	0	1	1
Colorado	0.5	0	0	0	0	0	0.5	1
District of Columbia	0.5	0	0	0	0	0.5	0	1
Florida	0	0	0	0	0	0.5	0.5	1
Hawaii	0	0.5	0	0	0	0	0.5	1
Missouri	0	0	0	0	0	0	1	1
Montana	0.5	0	0	0	0	0	0.5	1
New Hampshire	0	0	0	0	0	0.5	0.5	1
North Carolina	0.5	0	0	0	0	0	0.5	1
Tennessee	0	0	0	0	0	0	1	1
Utah	0.5	0	0	0	0	0	0.5	1
Georgia	0	0	0	0	0	0	0.5	0.5
Idaho	0	0	0	0	0	0	0.5	0.5
Indiana	0.5	0	0	0	0	0	0	0.5
Kansas	0	0	0	0	0	0	0.5	0.5
Kentucky	0	0	0	0	0	0	0.5	0.5
Louisiana	0	0	0	0	0	0	0.5	0.5
Mississippi	0	0	0	0	0	0	0.5	0.5
Nevada	0	0	0	0	0	0	0.5	0.5
North Dakota	0	0	0	0	0	0.5	0	0.5
Puerto Rico	0	0	0	0	0	0.5	0	0.5
South Dakota	0.5	0	0	0	0	0	0	0.5
West Virginia	0	0	0	0	0	0.5	0	0.5
Alabama	0	0	0	0	0	0	0	0
Arkansas	0	0	0	0	0	0	0	0
Guam	0	0	0	0	0	0	0	0
Nebraska	0	0	0	0	0	0	0	0
Oklahoma	0	0	0	0	0	0	0	0

State	Intercon-nection (0.5 pts.)	Encouraging CHP as a resource: EERS treatment (0.5 pts.)	Encouraging CHP as a resource: CHP program (0.5 pts.)	Encouraging CHP as a resource: Produc-tion goal (0.5 pts.)	Encouraging CHP as a resource: Revenue streams (0.5 pts.)	Deployment incentives (0.5 pts.)	Supportive policies (1 pt.)	Total score (4 pts.)
South Carolina	0	0	0	0	0	0	0	0
US Virgin Islands	0	0	0	0	0	0	0	0
Virginia	0	0	0	0	0	0	0	0
Wyoming	0	0	0	0	0	0	0	0

Massachusetts, California, and Maryland tied for the top score again this year, with each state earning the full 4 points. These states and Maine and New York were the only ones to receive credit for a state-approved production goal for CHP generation, which is a strong policy driver for encouraging utilities and program administrators to acquire generation from CHP. However even the top-scoring states can do more to encourage CHP. For example, California meets all the criteria in our scoring methodology, but barriers to deployment still exist, especially around air permitting, and state policies and programs could be improved to more effectively treat CHP as an energy efficiency resource.

New York and Rhode Island earned the second-highest ranking, with 3.5 points each. All of the highest-scoring states (those earning 3–4 points) define CHP as an eligible resource in an energy efficiency resource standard, have utility- or program administrator–run CHP programs designed to acquire CHP as a resource, and provide access to revenue streams linked to actual KWh production. Maine, Connecticut, Minnesota, Oregon, Washington, and Pennsylvania rounded out the 10 highest-scoring states.

DISCUSSION

Interconnection Standards

States received 0.5 points for having an interconnection standard that explicitly established parameters and procedures for the electrical interconnection of CHP systems. To earn points in this category, a state's interconnection standard had to

- Be adopted by utilities serving the majority of the state's customers
- Cover all forms of CHP, regardless of fuel
- Have multiple tiers of interconnection and some kind of fast-track option for smaller systems
- Apply to systems 10 MW or greater

Having multiple levels (or tiers) of interconnection is important because larger CHP systems are more complex than smaller ones. Because of the potential for impacts on the utility grid, the interconnection of larger systems requires more extensive approvals. These are unnecessary and financially burdensome for smaller systems, which can benefit from a faster and often cheaper path toward interconnection. Scaling transaction costs to project size makes economic sense. Additionally, CHP developers prefer interconnection standards that cover higher size limits and are based on widely accepted technical industry standards, such as IEEE 1547.[47]

Encouraging CHP as a Resource

While CHP is known for its energy efficiency benefits, few states actively identify it as an energy resource akin to more traditional sources such as centralized power plants. CHP can offer energy, capacity, and even ancillary services to grids to which they are connected, but to maximize those benefits, states must first identify CHP as a resource and integrate it into system planning and energy resource acquisition efforts.[48] One of the best ways to do this is to include CHP within state energy efficiency goals and utility programs.

States could receive up to 2 points for activities and policies that encourage CHP as an energy resource. We considered the following subcategories in awarding points:

EERS treatment. We awarded 0.5 points if CHP was clearly defined as eligible in a binding EERS or similar requirement. Most states with EERS policies set goals for future years. These goals are generally a percentage of total electricity sold that must be derived from efficiency resources, with the percentage of these resources increasing over time. To receive credit, a state's EERS must explicitly apply to CHP powered by natural gas, be technology neutral, and be a binding obligation.

CHP resource acquisition programs. We awarded 0.5 points for programs designed to acquire cost-effective CHP in a way similar to the acquisition of other energy efficiency resources. For a state to earn this half point, a majority of its energy customers must have access to clearly defined CHP programming offered by major utilities or other program administrators. We did not give credit if only a small selection of customers have access to a CHP program or if a state has a custom commercial or industrial incentive program that could theoretically be used for CHP but is not marketed as a CHP program. To earn credit, states have to be actively reaching out to potential CHP users and developers to market the program, and they must be acquiring new CHP resources as a result.

Production goal. We awarded 0.5 points for the existence of either a state-approved production goal (kWh) from CHP resources or a program budget for the acquisition of a defined amount of kWh savings from CHP by utilities or program administrators. The presence of either (or both) of these indicates that a state has identified CHP as a resource and, importantly, has given utilities a clear signal to develop and deploy programming designed to acquire CHP. In many states, utilities report receiving mixed signals about whether their regulators are actually supportive of program spending tied to CHP. This

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[47] This standard establishes criteria and requirements for interconnection of distributed energy resources with electric power systems. It provides requirements relevant to the performance, operation, testing, safety, and maintenance of the interconnection. For more information, visit www.ieee.org.

[48] The Federal Energy Regulatory Commission (FERC) defines ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system. Ancillary services supplied with generation include load following, reactive power-voltage regulation, system protective services, loss compensation service, system control, load dispatch services, and energy imbalance services." For more information, visit www.ferc.gov/market-oversight/guide/glossary.asp.

subcategory addresses this particular issue of utility incentives and disincentives to pursue CHP programming.

Revenue streams. We awarded 0.5 points to states that provide access to favorable revenue streams for CHP, including production incentives ($/kWh), feed-in tariffs, standard offer programs, or other revenue streams linked to kWh production. These incentives are specifically designed to encourage measurable energy savings from CHP. Production incentives are linked directly to a CHP system's production or to some calculated amount of energy savings relative to an established baseline. Feed-in tariffs usually specify $/kWh payment to CHP operators for exporting electricity to the grid, providing price certainty and long-term contracts that can help finance CHP systems (EPA 2015b). Standard offer programs offer a set price for qualifying CHP production and often have a program cap or point at which the standard offer will no longer be available. Revenue streams through net metering are treated in a separate category described later in this chapter.

In general, we did not give credit for custom program offerings marketed to commercial and industrial sectors that could only *potentially* be used for CHP, as the spending and savings for these programs are reflected in other parts of the *State Scorecard*. However we did give credit for programs that included a specific CHP-focused component, such as the identification of and outreach to potential sites for CHP installations.

To earn points in any of the four subcategories outlined above, a state policy or program must be usable by all customer classes and apply to CHP systems powered by natural gas. Detailed information on the policies and programs that earned points in this category is available in the CHP section of the ACEEE State and Local Policy Database (ACEEE 2016).

Deployment Incentives

States could receive 0.5 points for the presence of deployment incentives that improve the economics of a CHP investment but are not necessarily tied to resource acquisition efforts by utilities. Deployment incentives can encourage CHP at the state level in a variety of ways, and the leading states have multiple types of incentive programs. To earn points in this category, at least one available incentive must

- Apply to all CHP, regardless of fuel
- Be an investment tax credit, a credit for installed capacity, a loan or loan guarantee, a project grant, or a net metering standard
- Apply to both the commercial and the industrial sectors

Tax incentives for CHP can take many forms, but are often credits taken against business or real estate taxes. The US Internal Revenue Service (IRS) administers a federal business energy investment tax credit (ITC) that incentivizes CHP systems by offering a credit for 10% of CHP project costs (DSIRE 2016). Tax credits administered by a state can similarly provide support for CHP deployment. Although the federal ITC is set to expire on December 31, 2016, tax incentives are usually considered more permanent incentive structures than grant programs.

State grants can also support CHP deployment by providing financing for capital and other costs. Some grant awards and other simple incentive programs offer rebates or payments linked to the installation of CHP capacity with amounts set in $/kW. Many of these programs are administered in conjunction with production incentives. Low-interest loan programs, loan guarantees, and bonding authorities are other strategies states can use to make CHP systems financially attractive and reduce the cost of financing. To earn points for these programs, a state must clearly identify CHP as an eligible project type and market it to CHP project developers who then take advantage of the financing opportunity.

Net metering regulations can also incentivize CHP deployment by allowing owners of small distributed generation systems to get credit for net excess electricity that they produce onsite. With wholesale net metering, sometimes known as *dual-meter metering*, utilities pay customers at the wholesale or avoided-cost rate for any excess electricity exported to the grid. We gave credit to states that explicitly list CHP as an eligible technology and offered at least wholesale net metering to all CHP systems, regardless of fuel, in all customer classes.

Detailed information on incentives for CHP is available from the EPA's CHP Policies and Incentives Database (EPA 2016) and from the Database of State Incentives for Renewables and Efficiency (DSIRE 2016).[49]

Additional Supportive Policies

A state could receive up to 1 point for activities or additional policies that support the deployment of CHP. Because barriers to deployment and opportunities to encourage CHP vary from state to state, this category recognizes a wide variety of efforts that states can undertake. States earned 0.5 points for the presence of any one of the following supportive policies, or 1 point for the presence of two or more

- Policies that encourage the use of opportunity fuels in conjunction with CHP technologies, such as biomass, biogas, anaerobic digester gas, landfill gas, wood, and other waste (including waste heat)
- Streamlined air permitting procedures, including permit-by-rule, for CHP systems for multiple major pollutants
- Dedicated CHP-focused technical assistance efforts
- Requirements that public buildings and/or other critical facilities consider CHP during times of upgrade and new construction
- Policies and programs that specifically encourage CHP for its resiliency and reliability benefits

In previous years, we assigned points separately for the eligibility of CHP in a state's EERS and its RPS to note the different roles the two standards can play. As with EERSs, most states with RPS policies set goals for future years that require a percentage of the total electricity sold to be derived from renewable resources. This year, states could earn points for RPSs and other policies that encourage the use of renewable-fueled CHP as an additional supportive policy. The availability of biomass and biogas resources is often local, and some

[49] EPA's database is available at www.epa.gov/chp/policies/database.html. The DSIRE database is available at www.dsireusa.org.

states are better suited to use these resources than others. Natural gas is available nearly everywhere in the United States and is the predominant fuel used by CHP systems. While natural gas CHP systems do not generally benefit from RPS treatment, biomass or biogas systems often do, and we recognize the use of these and other opportunity fuels in this category.

States could also earn points for streamlined air permitting, including permit-by-rule processes. These are alternatives to conventional air permits that help reduce the time and cost involved in permitting eligible CHP units. Additional information about approaches to streamline air permitting for CHP is available in an EPA fact sheet (EPA 2014).

States could earn points for several other supportive policies in this category. Such policies can include targeted technical assistance programs, education campaigns, or other state-led special efforts that support CHP. To earn credit for technical assistance, a state's efforts must go beyond the critical services provided by DOE's CHP Technical Assistance Partnerships. States could also earn points for requirements to consider CHP for public buildings and critical facilities during times of upgrade or new construction, or for programs that encourage the consideration of CHP's resiliency benefits during grid outages. The ACEEE State and Local Policy Database's CHP section contains state-by-state descriptions of these policies (ACEEE 2016).

ADDITIONAL METRICS

Two additional metrics are noted but do not impact a state's score. Below, we include data on both the number of individual CHP systems installed and the total capacity (MW) installed in each state.[50] We believe information on actual installations is useful for comparing CHP activity states, but does not in itself fully indicate a state's CHP friendliness. Table 30 shows the number of new CHP systems and installed CHP capacity over the past two years.

The 2015 data show a lower level of installed CHP capacity than we have seen in recent years. This is due to the absence of any very large installations (e.g., greater than 50 MW), which tend to contribute a high percentage of the annual capacity. Thus, while the number of installations is in the typical range, the amount of capacity in 2015 was lower than in prior years.

Various economic considerations determine how many CHP projects are installed, but the retail price of energy is a major factor in their economic attractiveness. Higher electricity prices may improve the case for CHP in some states, where self-generation can be more cost effective than purchasing electricity from the grid. In other states, lower and stable natural gas prices can help hasten investment in CHP systems, since many are fueled by natural gas.

While not assessed in the *Scorecard* since states cannot control the price of electricity or gas that customers pay, these prices drive a state's CHP market to varying degrees. Policymakers can implement policies that help overcome economic barriers raised in part by

[50] We use data from the DOE CHP Installation Database maintained by ICF International. The data reflected in the *State Scorecard* were released June 1, 2016 and reflect installations as of December 31, 2015 (DOE 2016c).

lower electricity prices or higher gas prices. Future editions of the *State Scorecard* may account for these factors by scoring states on their installed CHP capacity relative to some measure of technical or economic potential, or by assessing the degree to which unfavorable economics are minimized by certain regulatory or policy treatments.

Table 30. Number of new CHP systems and installed CHP capacity by state, 2014–2015

State	Number of new CHP installations in 2015	New capacity installed in 2015 (MW)	Number of new CHP installations in 2014	New capacity installed in 2014 (MW)	Total number of new CHP installations	Total new capacity installed (MW)
Alabama	0	0	1	0.8	1	0.8
Alaska	0	0	4	3.1	4	3.1
Arizona	1	0.1	1	8.1	2	8.2
Arkansas	1	5.2	0	0.0	1	5.2
California	28	82.9	34	106.7	62	189.6
Colorado	2	2.9	1	3.1	3	6.0
Connecticut	8	4.3	2	0.8	10	5.1
Delaware	1	4.0	1	0.1	2	4.1
District of Columbia	2	18.5	0	0.0	2	18.5
Florida	0	0	3	17.7	3	17.7
Georgia	1	28.0	0	0.0	1	28.0
Hawaii	1	1.0	1	1.7	2	2.7
Idaho	2	5.6	0	0.0	2	5.6
Illinois	0	0	7	1.3	7	1.3
Indiana	0	0	1	14.0	1	14.0
Iowa	1	2.8	1	15.3	2	18.1
Kansas	3	50.1	1	21.0	4	71.1
Kentucky	1	0.5	2	17.2	3	17.7
Louisiana	0	0	0	0.0	0	0.0
Maine	1	0.1	2	0.7	3	0.8
Maryland	0	0	8	8.6	8	8.6
Massachusetts	6	16.9	8	3.6	14	20.5
Michigan	1	13.0	5	3.3	6	16.3
Minnesota	0	0	2	0.7	2	0.7
Mississippi	0	0	0	0.0	0	0.0
Missouri	0	0	1	0.8	1	0.8
Montana	1	0.1	0	0.0	1	0.1
Nebraska	0	0	0	0.0	0	0.0

State	Number of new CHP installations in 2015	New capacity installed in 2015 (MW)	Number of new CHP installations in 2014	New capacity installed in 2014 (MW)	Total number of new CHP installations	Total new capacity installed (MW)
Nevada	0	0	1	0.0	1	0.0
New Hampshire	0	0	0	0.0	0	0.0
New Jersey	8	0.9	5	1.4	13	2.3
New Mexico	0	0	1	6.5	1	6.5
New York	36	6.5	44	21.4	80	27.9
North Carolina	0	0	6	42.1	6	42.1
North Dakota	0	0	1	99.0	1	99.0
Ohio	1	0.2	5	6.0	6	6.2
Oklahoma	0	0	0	0.0	0	0.0
Oregon	2	2.1	0	0.0	2	2.1
Pennsylvania	2	0.4	6	9.4	8	9.8
Rhode Island	1	1.0	1	12.5	2	13.5
South Carolina	1	4.5	0	0.0	1	4.5
South Dakota	0	0	0	0.0	0	0.0
Tennessee	1	7.0	1	2.1	2	9.1
Texas	4	31.1	12	868.9	16	900.0
Utah	0	0	0	0.0	0	0.0
Vermont	0	0	2	0.6	2	0.6
Virginia	0	0	2	15.3	2	15.3
Washington	2	0.7	0	0.0	2	0.7
West Virginia	0	0	1	0.8	1	0.8
Wisconsin	4	2.1	2	10.6	6	12.7
Wyoming	0	0	0	0.0	0	0.0
Total	**123**	**292.5**	**176**	**1,325.2**	**299**	**1,617.7**

Source: DOE 2016c

In general, states enacted few notable policies to enhance CHP's attractiveness in the year since we published the *2015 State Scorecard*. However activities did increase support for CHP in some states, and we describe a sampling of these efforts below.

Leading and Trending States: Policies to Encourage CHP Development

New Jersey. In October 2015, the New Jersey Energy Resilience Bank (ERB) updated several aspects of its program and expanded eligibility to include hospitals, small businesses, and private utilities. The bank provides grants and loans for resilient distributed energy resource (DER) projects, including CHP systems. The DER system must be designed to provide energy to all designated critical loads during a seven-day grid outage without a delivery of fuel to emergency generators. The grant portion is calculated on a project-by-project basis and must not be less than 40% of the eligible costs, including new CHP equipment, switchgear, engineering, and installation. In addition, the CHP and Fuel Cell program offered through New Jersey's Clean Energy Program was amended on July 1, 2015 to increase grant aid for CHP projects over 500 kW. The new incentive structure also significantly increases grant amounts for CHP projects over 1 MW.

Missouri. Missouri's Department of Economic Development, Division of Energy, is participating in efforts to encourage CHP based on recommendations outlined in its Comprehensive State Energy Plan published in October 2015. Several areas of the plan address concepts, benefits, and opportunities for new CHP installations. The plan includes recommendations to "establish cost-based standby rates and interconnection practices that reflect best practices" as well as to "promote the development of public/private partnerships to implement energy conservation measures, including CHP." The division also supports CHP deployment through participation in regulatory proceedings before the Missouri Public Service Commission. In addition, the agency is promoting the potential for CHP at state-owned facilities by leading a CHP feasibility study for the Capitol Complex in Jefferson City.

Pennsylvania. The Pennsylvania Public Utilities Commission and other entities are working to promote CHP through a policy statement published in the Pennsylvania Bulletin on April 16, 2016. The Commission is examining the viability of increased CHP implementation through research and consultation with industry experts. The policy statement's purpose is to encourage electricity distribution companies (EDCs) and natural gas distribution companies (NGDCs) to make CHP an integral part of their energy efficiency and resiliency plans, design and improve interconnection and standby rates, and promote the consideration of special natural gas rates for owners and operators of CHP facilities. EDCs and NGDCs will be required to report on their CHP activities.

Ohio. Several utilities in Ohio are offering new CHP incentives for customers in their service territories. In May 2015, Dayton Power & Light (DP&L) launched a CHP incentive program that provides up to $500,000 for CHP projects with generating capacities less than 500 kW (not to exceed 50% of the project cost). CHP projects must meet annual efficiency levels of 65% or higher. The rebates include $0.08 per kWh generated and $100 per kW capacity. In 2016, AEP Ohio also announced plans to spend close to $10 million on CHP incentives on an estimated 15–20 projects from 2017 to 2019. CHP technologies qualify as an eligible resource in Ohio's energy efficiency portfolio standard (EEPS) under Senate Bill 315. These programs indicate that Ohio utilities are shifting toward treating CHP as a resource.

Chapter 6. State Government-Led Initiatives

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INTRODUCTION

State legislatures and governors can advance energy efficiency policies and programs that affect the utilities, transportation, buildings, and CHP sectors discussed in previous chapters. In this chapter, we focus on energy efficiency initiatives that are designed, funded, and implemented by state entities, including energy offices, public universities, economic development agencies, and general services agencies.

We focus on four initiatives commonly undertaken by state governments: financial incentive programs for consumers, businesses, and industry; policies that require building owners or managers to be transparent in their energy use; lead-by-example policies and programs to improve the energy efficiency of public facilities and fleets; and R&D for energy efficiency technologies and practices.

SCORING AND RESULTS

States could earn up to 7 points in this policy area:

- Financial incentives offered by state agencies (3 points)
- Residential and commercial energy use disclosure policies (1 point)
- Lead-by-example policies (2 points)
- Publicly funded R&D programs focused on energy efficiency (1 points)

Table 31 presents the overall results of scoring on state initiatives.

Table 31. Summary of scores for government–led initiatives

State	Financial incentives (3 pts.)	Benchmarking and transparency (1 pt.)	Lead by example (2 pts.)	R&D (1 pt.)	Total score (7 pts.)
California	3	1	2	1	7
Washington	3	0.5	2	1	6.5
Colorado	3	0	2	1	6
Connecticut	3	0	2	1	6
Massachusetts	3	0	2	1	6
Minnesota	3	0	2	1	6
New York	3	0.5	1.5	1	6
Tennessee	3	0	2	1	6
Maryland	3	0	1.5	1	5.5
Oregon	3	0	1.5	1	5.5
Alaska	3	0.5	1	0.5	5
Kentucky	3	0	1.5	0.5	5
Maine	2.5	0.5	1.5	0.5	5

State	Financial incentives (3 pts.)	Benchmarking and transparency (1 pt.)	Lead by example (2 pts.)	R&D (1 pt.)	Total score (7 pts.)
Missouri	2.5	0	1.5	1	5
Pennsylvania	3	0	1	1	5
Rhode Island	2.5	0	2	0.5	5
Vermont	2.5	0	2	0.5	5
Virginia	3	0	1	1	5
Delaware	1.5	0	2	1	4.5
Michigan	3	0	1.5	0	4.5
Texas	1.5	0	2	1	4.5
Utah	1.5	0	2	1	4.5
District of Columbia	1	1	1.5	0.5	4
Illinois	1	0	2	1	4
Nevada	2	0	1.5	0.5	4
North Carolina	1	0	2	1	4
Ohio	2.5	0	1	0.5	4
Wisconsin	1.5	0	1.5	1	4
Arkansas	2	0	1.5	0	3.5
Florida	1.5	0	1	1	3.5
Iowa	1.5	0	1	1	3.5
Montana	1.5	0	2	0	3.5
New Hampshire	1.5	0	2	0	3.5
South Carolina	2	0	1.5	0	3.5
Alabama	1.5	0	1	0.5	3
Arizona	1	0	1	1	3
Hawaii	0.5	0.5	1.5	0.5	3
Idaho	2	0	0.5	0.5	3
Kansas	0	0.5	1.5	1	3
Mississippi	1	0	1.5	0.5	3
New Mexico	1	0	2	0	3
Georgia	0	0	1.5	1	2.5
Nebraska	1	0	0.5	1	2.5
Puerto Rico	0	0	1.5	1	2.5
New Jersey	0.5	0	1	0.5	2
Wyoming	1.5	0	0.5	0	2
Indiana	0.5	0	0.5	0.5	1.5

State	Financial incentives (3 pts.)	Benchmarking and transparency (1 pt.)	Lead by example (2 pts.)	R&D (1 pt.)	Total score (7 pts.)
Louisiana	0.5	0	1	0	1.5
Oklahoma	1.5	0	0	0	1.5
Guam	0.5	0	0.5	0	1
South Dakota	0	0.5	0.5	0	1
North Dakota	0.5	0	0	0	0.5
US Virgin Islands	0	0	0.5	0	0.5
West Virginia	0	0	0	0.5	0.5

DISCUSSION

Financial Incentives

While utilities offer ratepayer-funded energy efficiency programs, many states also provide financial incentives to spur the adoption of technologies and practices in homes and businesses. These incentives can be administered by various state agencies, but they are most often coordinated by state energy offices. Incentives can take many forms: rebates, loans, grants, or bonds for energy efficiency improvements; income tax credits and deductions for individuals or businesses; and sales tax exemptions or reductions for eligible products. Financial incentives can lower the up-front cost and shorten the payback period for energy efficiency upgrades, shrinking two barriers for consumers and businesses who hope to make cost-effective efficiency investments. Incentives also raise consumer awareness of eligible products, encouraging manufacturers and retailers to market these products more actively and to continue to innovate. As economies of scale improve, prices of energy-efficient products fall, and the products eventually compete in the market without the incentives.

SCORES FOR FINANCIAL INCENTIVES

We relied primarily on the Database of State Incentives for Renewables and Efficiency for information on current state financial incentive programs (DSIRE 2016). We supplemented these data with information from a survey of state energy officials and a review of state government websites and other online resources.

We did not give points in this category for utilities' customer-funded financial incentive programs, which we covered in Chapter 2. Acceptable sources of funding included state appropriations or bonds, oil overcharge revenues, auction proceeds from the RGGI or California's cap-and-trade program, other noncustomer sources, and tax incentives. While state and customer funding sometimes overlap—for example, where state incentives are funded through a systems benefits charge—we designed this category to capture energy efficiency initiatives not already covered in Chapter 2. We discuss energy efficiency financing in more detail at the end of this chapter.

This year, we expanded our eligibility criteria to recognize growing state efforts to leverage private dollars for energy efficiency programs. We continued to award points for loans offered by green banks with active energy efficiency programs. We also gave credit for the

PACE financing programs that many states are enabling. From 2009 to 2015, energy efficiency projects accounted for 48% of PACE financing (PACENation 2015). State legislatures pass and amend legislation enabling residential and/or commercial PACE, and localities and private program administrators typically run the programs, depending on the jurisdiction.[51] Sometimes states play a more prominent role in PACE coordination by administering a statewide program or offering guidance to PACE providers (Fazeli 2016). Because programs are locally administered, we did not give extra credit for multiple active PACE programs; however we indicate in the table below whether state PACE activity is in the residential and/or commercial market.

States earned up to 3 points for major financial incentive programs that encourage the purchase of energy-efficient products. We judged these programs on their relative strength, customer reach, and impact.[52] Incentive programs generally received 0.5 points each, but several states have major incentive programs that we deemed worth 1 point each; these include Arizona, Idaho, Nebraska, Nevada, Texas, Washington, and Wisconsin. We credited states that have enabled PACE and have at least one active PACE program. States could receive a maximum of 0.5 points for PACE. Table 32 describes our scoring of state financial incentives.

The number of financial incentive programs a state implements may not fully reflect the robustness of its efforts, so this year we attempted to collect additional information from state energy offices regarding state budgets for financial incentives, program participation rates, verified savings from incentives, and leveraging of private capital. These data are presented in Appendices H, I, and J. For additional information, see the end of this chapter, where we discuss potential new metrics for state-led initiatives.

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[51] Currently, 32 states plus Washington, DC authorize PACE (PACENation 2016). While most states' PACE activity is in the commercial market, there have been several residential PACE programs over the last several years. In July 2016, the Federal Housing Administration, the DOE, and the Department of Veteran Affairs issued new guidance and best practices on residential PACE, which are expected to lay the groundwork for future residential PACE programs. For more information on these announcements, part of the White House's Clean Energy Savings for All Americans initiative, visit: www.whitehouse.gov/the-press-office/2016/07/19/fact-sheet-obama-administration-announces-clean-energy-savings-all.

[52] Energy-efficient products include any product or process that reduces energy consumption. While renewable energy technologies such as solar hot-water heating may reduce energy consumption, they are often rolled into larger programs that focus on renewable energy rather than energy efficiency. ACEEE would like to credit states for renewable energy technologies that reduce energy consumption, but they are often difficult to distinguish from broader renewable energy incentives that fall outside of the scope of the *State Scorecard*. As a result, they are not included at this time.

Table 32. State scoring on major financial incentive programs

State	Major state financial incentives for energy efficiency	Score (3 pts.)
Alaska	New home rebate program; five loan programs; two grant programs	3
California	Five grants; two loans (public sector and education); a loan loss reserve; a rebate program; an R&D program; commercial and residential PACE financing	3
Colorado	Mortgage discount for ENERGY STAR homes; loan loss reserve program; school loan program; Dairy and Irrigation Efficiency audit program; commercial and residential PACE financing	3
Connecticut	Several loans; financing for multifamily and low- to moderate- income residential projects; commercial financing	3
Kentucky	Personal and corporate energy efficiency tax credits; green bank loan for state agencies; sales tax exemption for energy-efficient products; three grants; commercial PACE financing	3
Maryland	Different loans and grant programs for agricultural residential, multifamily, commercial, and industrial sectors; Smart Energy Communities Program; loans for state agencies; commercial PACE financing	3
Massachusetts	Alternative Energy and Energy Conservation Patent Exemption (personal and corporate); one bond; three grants	3
Michigan	Michigan Saves financing; five loans; four grants; a loan loss reserve; commercial PACE financing	3
Minnesota	Six loans; two revolving loans; one loan loss reserve; commercial PACE financing	3
New York	Green Jobs Green NY Program; rebate, loan, grant, financing, and incentive programs; Energy Conservation Improvements Property Tax Exemption; green bank; commercial and residential PACE financing	3
Oregon	Several residential and business energy tax credits; one loan program; one grant program; commercial PACE financing	3
Pennsylvania	Alternative Energy Investment Fund; Pennsylvania Sustainable Energy Finance Program; several grant and loan programs	3
Washington	Major grant program for energy efficiency in public facilities and local communities; three loans; two grants	3
Virginia	Energy Leasing Program for state-owned facilities; Clean Energy Manufacturing Grant Program; one loan program; personal and property tax incentives; commercial PACE financing; Clean Energy Development and Services (CEDS) program	3
Tennessee	Energy Efficient Schools Initiative (loans and grants); two grants; one loan; EmPower TN incentives	3
Vermont	Three loan programs; Weatherization Trust Fund; Thermal Efficiency Finance Program	2.5
Missouri	Two loan programs; one personal tax deduction; commercial and residential PACE financing	2.5

State	Major state financial incentives for energy efficiency	Score (3 pts.)
Ohio	Two loans and one grant program; property tax exemption for energy-efficient projects; commercial PACE financing	2.5
Rhode Island	One loan; one rebate; two revolving loan programs; commercial PACE financing	2.5
Maine	Residential rebates (single and multifamily); commercial rebate; advanced building incentive; Low-Income Heat Pump Initiative	2.5
South Carolina	Tax credits for new energy-efficient manufactured homes; sales tax cap on energy-efficient manufactured homes; two loan programs	2
Nevada	Wide-reaching property tax abatement for green buildings; Home Energy Retrofit Opportunities for Seniors (HEROS); loans for state employees	2
Idaho	Income tax deduction for energy efficiency improvements; grant program for school districts; one major low-interest loan program	2
Arkansas	Three loans; commercial PACE financing	2
Oklahoma	Three loan programs	1.5
Alabama	Two state-funded loan programs; WISE Home Energy Program (loans)	1.5
Delaware	Three loan programs	1.5
Florida	Rebates for farm energy efficiency; REET grant matching program; commercial and residential PACE financing	1.5
Wyoming	One loan and two grant programs	1.5
Iowa	Energy Bank Revolving Loan Program; Alternate Energy Revolving Loan Program; Technology Demonstration and Education Grants	1.5
Montana	Energy conservation installation tax credit; tax deduction for energy-conserving investment; Alternative Energy Revolving Loan Program	1.5
Texas	One major loan program (Texas LoanSTAR); commercial PACE financing	1.5
Utah	Two loan programs for state-owned buildings and schools; commercial PACE financing	1.5
Wisconsin	One major loan program (Clean Energy Manufacturing Loan Program); commercial PACE financing	1.5
New Hampshire	Two revolving loan funds; commercial PACE financing	1.5
Illinois	One loan program; one bond program	1
Arizona	Property tax exemption for energy-efficient building components and CHP	1
District of Columbia	Green Light Grant; commercial PACE financing	1
Mississippi	One loan program; one public sector lease program for energy-efficient equipment	1
Nebraska	One major loan program (Dollar and Energy Savings Loans)	1
New Mexico	Sustainable Building Tax Credit (corporate); bond program	1
North Carolina	One rebate and one loan program	1

State	Major state financial incentives for energy efficiency	Score (3 pts.)
New Jersey	Commercial PACE financing	0.5
Hawaii	GreenSun Hawaii loan program	0.5
Louisiana	Home Energy Loan Program (HELP)	0.5
Indiana	Tax credit for purchase and installation of residential insulation	0.5
North Dakota	One grant program	0.5
Guam	Rebate for energy-efficient appliances	0.5
Georgia	None	0
Kansas	None	0
Puerto Rico	None	0
South Dakota	None	0
US Virgin Islands	None	0
West Virginia	None	0

Leading and Trending States: Financial Incentives

Tennessee. In partnership with Pathway Lending, Tennessee provides low-interest energy efficiency loans to businesses and local government entities through the Pathway Lending Energy Efficiency Loan Program (EELP). Pathway Lending operates and manages this revolving loan fund, to which the State of Tennessee committed $15 million, the Tennessee Valley Authority committed $14 million, and Pathway Lending committed $5 million. Loans issued in 2015 as part of this program saved participants more than 9,000 MWh and $1 million. The state also offers grants to utility districts and state and local governments for projects that promote energy efficiency or clean energy technologies. Through the Energy Efficiency Schools Initiative, Tennessee uses excess state lottery funds for grants and loans to school systems for capital outlay projects that meet energy efficiency guidelines. To date, 95% of school districts have participated in one or more grant programs.

Florida. Through its Farm Energy and Water Efficiency Realization (FEWER) program, the Florida Department of Agriculture and Consumer Services offers farmers free energy audits to determine the potential for renewable energy, energy efficiency, and water-saving measures. Eligible agricultural producers can receive up to $25,000 for implementing recommended measures. Florida also offers both commercial and residential PACE financing as well as matching funds for entities to conduct research, development, demonstration, and commercialization projects on energy efficiency in vehicles or commercial buildings.

Missouri. With a $720 million 2015 budget, the Missouri Linked Deposit Program provides low-interest loans for use in energy efficiency measures through building renovations, repairs and maintenance, purchase of equipment and facilities for businesses, farming operations, and multifamily housing. The Missouri state treasurer administers this program and leverages capital from private lending institutions. In addition, the state offers energy efficiency tax incentives for homeowners, a revolving loan fund for public buildings, a loan loss reserve fund for livestock farmers, and both commercial and residential PACE financing.

Buildings Energy Use Transparency

Building energy benchmarking and transparency laws require property owners, builders, or sellers to compile and report information about their buildings' energy use or energy efficiency characteristics to a centralized database and/or to prospective buyers at the time of sale. This information can then be used to evaluate building energy use patterns and identify energy efficiency opportunities. A study by the US Environmental Protection Agency showed that benchmarking energy use led to a 7% decrease in consumption across a sample of more than 35,000 buildings (ENERGY STAR 2012). Benchmarking and transparency requirements improve consumers' awareness of the energy use of homes and commercial buildings up for sale or lease. This information can also have an impact on the value of a home or building. Laws requiring building owners and managers to report energy use might also motivate owners to improve their building's energy efficiency.

Energy use transparency requirements are a fairly recent policy innovation. Commercial transparency policies are uncommon at the state level, with only California, Washington, and the District of Columbia requiring energy use disclosure upon sale or lease (IMT 2016). Local governments are more likely to pursue these policies, but state governments can also use them to incentivize building stock upgrades.

SCORES FOR BUILDING ENERGY USE DISCLOSURE REQUIREMENTS

We based our review of benchmarking and energy use transparency laws on policy information compiled by the Institute for Market Transformation's BuildingRating.org project (IMT 2016). States with mandatory energy use transparency laws received 0.5 points for a policy covering commercial or residential buildings. States with both policies in place for some or all of their commercial and residential buildings received 1 point. Table 33 presents the state disclosure policies.

Table 33. State benchmarking and energy transparency policies

State	Disclosure type	Building energy use transparency requirements	Score (1 pt.)
District of Columbia	Commercial, residential, multifamily	The Clean and Affordable Energy Act of 2008 requires privately owned commercial buildings to be benchmarked using EPA Energy Star Portfolio Manager on an annual basis. Results are publicly available in the Build Smart DC database.	1
California	Commercial, residential, multifamily	Assembly Bill 1103 requires nonresidential building owners or operators to benchmark their buildings' energy use using EPA ENERGY STAR Portfolio Manager and to disclose this information to buyers, lenders, and lessees. Assembly Bill 802 expands this requirement to any building with five or more active utility accounts, including residential multifamily buildings.	1
Alaska	Residential	Alaska statute AS.34.70.101 requires the release of utility data for residential buildings at the time of sale.	0.5
Hawaii	Residential	§508D-10.5 requires residential property owners to disclose energy-efficiency consumer information at the time of sale or lease.	0.5

State	Disclosure type	Building energy use transparency requirements	Score (1 pt.)
Kansas	Residential	HB 2036 requires builders or sellers of new residential single-family or multifamily buildings of four units of less to disclose information regarding the energy efficiency of the structure to buyers (or prospective buyers) prior to signing the contract to purchase and closing the sale.	0.5
Maine	Residential	H.P. 1468 requires the disclosure of an energy efficiency checklist and allows for the release of audit information of residential buildings, both at the time of sale.	0.5
New York	Residential	Beginning in 1981, the Truth in Heating law required the release of residential buildings' utility data at the time of sale.	0.5
South Dakota	Residential	SB 64 (2009) established certain energy efficiency disclosure requirements for new residential buildings at the time of sale.	0.5
Washington	Commercial	SB 5854 (2009-10) requires all nonresidential customers and qualifying public agency buildings to benchmark their buildings' energy use using EPA ENERGY STAR Portfolio Manager and to disclose this information to buyers, lenders, and lessees.	0.5

Policies based on IMT 2016 and data requests to state energy offices.

Several states have taken the lead in requiring benchmarking and energy use transparency, but no additional disclosure policies have been adopted since last year's *Scorecard*. The District of Columbia and California are the only jurisdictions we surveyed that have such requirements for both the commercial and residential multifamily sectors. As benchmarking and energy use transparency policies become more common, more states will likely expand their scope to target more buildings across both markets. However local jurisdictions are more likely to pursue these policies. Most recently, Kansas City Missouri, Portland, and Seattle adopted benchmarking ordinances.[53]

Leading and Trending States: State Benchmarking and Energy Use Transparency Policies

California. In 2015, California enacted an improved statewide benchmarking program, replacing the one previously established in AB 1103 that covered only nonresidential buildings. The new policy expands the state benchmarking requirement to residential multifamily and mixed-use buildings. It also makes it easier for utilities to provide whole-building energy use data to property owners and requires them to do so when requested.

District of Columbia. Since 2014, the District has required all commercial and multifamily buildings over 50,000 square feet and all city government buildings over 10,000 square feet to report annual energy and water use to the District Department of Energy and Environment. In March 2016, the city published energy and water consumption data for 1,498 buildings, representing more than 278 million square feet. The District uses EPA's ENERGY STAR Portfolio Manager to measure total building energy use, energy intensity, and carbon emissions.

[53] For more information on how municipalities are encouraging building energy disclosure, see Ribeiro et al. (2015) and Cluett and Amann (2013).

Lead by Example

State governments can advance energy-efficient technologies and practices in the marketplace by adopting policies and programs to save energy in public-sector buildings and fleets, a practice commonly referred to as *lead by example*. In the current environment of fiscal austerity, lead-by-example policies and programs are a proven strategy for improving the operational efficiency and economic performance of states' assets. Lead-by-example initiatives also reduce the negative environmental and health impacts of high energy use and promote energy efficiency to the broader public.[54]

STATE BUILDING REQUIREMENTS

States often adopt policies and comprehensive programs to reduce energy use in state buildings. State governments operate numerous facilities, including office buildings, public schools, colleges, and universities, the energy costs of which can account for as much as 10% of a typical government's annual operating budget. In addition, the energy consumed by a state's facilities can account for as much as 90% of its GHG emissions (DOE 2008). Only a handful of states have not yet implemented an energy efficiency policy for public facilities. Mandatory energy savings targets for new and existing state government facilities are the most widely adopted state measures. These energy savings requirements encourage states to invest in the construction of new, efficient buildings and retrofit projects, lowering energy bills and promoting economic development in the energy services and construction sectors.

To earn points, energy savings targets must commit state government facilities to a specific energy reduction goal over a distinct time period. We also gave 0.5 points to states that adopted efficiency requirements for public facilities that exceeded the statewide building energy code.

BENCHMARKING REQUIREMENTS FOR PUBLIC BUILDINGS

Proper building energy management is a critical element of successful energy efficiency initiatives in the public sector. Benchmarking energy use in public-sector buildings through tailored or widely available tools such as ENERGY STAR Portfolio Manager ensures a comprehensive set of energy use data that can drive cost-effective energy efficiency investments.[55] Comparing building energy performance across agencies can also help prioritize energy efficiency projects.

Through benchmarking policies, states and cities require all buildings to undergo a regular energy audit or have their energy performance tracked using Portfolio Manager or another recognized tool. These policies were awarded 0.5 points. Large-scale public-sector energy benchmarking programs could also qualify for the 0.5 points.

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[54] Energy efficiency reduces society's need to burn fossil fuels to generate electricity, thereby reducing harmful pollutants from fossil fuel combustion. ACEEE and Physicians for Social Responsibility explore this connection in a joint fact sheet: aceee.org/fact-sheet/ee-and-health.

[55] Some states have their own databases of public building energy use that integrate with the ENERGY STAR Portfolio Manager. For example, Maryland's EnergyCap database compiles the energy use (based on utility bills) of all public buildings in the state and provides a means of comparing buildings owned by different state agencies.

ENERGY SAVINGS PERFORMANCE CONTRACTING POLICIES AND PROGRAMS

If state governments have the necessary support, leadership, and tools in place, they can help projects overcome information and cost barriers to implementation by financing energy improvements through energy savings performance contracts (ESPCs). The state may enter into an ESPC with an energy service company (ESCO), paying the company for its services with money saved by installing energy efficiency measures. A designated state agency may serve as the lead contact for implementing the contract.[56]

We based scores for ESPC activities on three metrics: support, leadership, and tools. To promote performance contracting, states must provide an enabling framework (support), in addition to the guidance and resources (leadership and tools) to get these projects off the ground. We awarded states 0.5 points if it satisfied at least two of the three criteria. Table 34 describes qualifying actions.

Table 34. Scoring of ESPC policies and programs

Criterion	Qualifying action
Support	The state explicitly promotes the use of ESPCs to improve the energy efficiency of public buildings through statutory requirements, recommendations, or explicit preferences for ESPC use; executive orders that promote or require ESPCs; and/or financial incentives for agencies seeking to use ESPCs.
Leadership	A state program directly coordinates ESPC, or a specific state agency serves as lead contact for implementing ESPCs.
Tools	The state offers documents that streamline and standardize the ESPC process, including a list of prequalified service companies, model contracts, and/or a manual that lays out the procedures required for state agencies to utilize ESPCs.

States must satisfy at least two of the three criteria above to receive credit.

EFFICIENT FLEETS

In addition to lead-by-example initiatives in state government buildings, many states also enact policies encouraging or requiring efficient vehicle fleets to reduce fleet fuel costs and hedge against rising fuel prices. Collectively, state governments own approximately 500,000 vehicles, with a median fleet size of about 3,500. Operation and maintenance costs for these fleets every year exceed $2.5 billion nationwide, ranging from $7 million to $250 million per state (NCFSA 2007). In response to these costs, states often adopt an efficiency standard specifically for state vehicle fleets that reduces fuel consumption and GHG emissions.

For this category, states received credit only if the plan or policy for increasing the efficiency of the state's fleet contained a specific, mandatory requirement. For example, states could qualify for 0.5 points if fleet policies specified fuel economy improvements that exceeded existing corporate average fuel economy (CAFE) standards. Other policies that earned the half point include binding goals to reduce petroleum use by a certain amount over a given time frame, meaningful GHG reduction targets for fleets, and procurement requirements for hybrid-electric or all-electric vehicles. Because state adoption of such targets does not guarantee they will be achieved, we might need to revisit this metric. We will continue to

[56] For a full discussion of ESPCs, the ESCO market, and actual implementation trends, see Satchwell et al. 2010 and the National Association of Service Companies' website, www.naesco.org.

seek data on state progress toward meeting these goals. We did not credit requirements for procuring alternative-fuel vehicles, because they may not result in improved fuel economy.

SCORES FOR LEAD BY EXAMPLE

We based our review of states' lead-by-example initiatives on information from the Database of State Incentives for Renewables and Efficiency (DSIRE 2016), a survey of state energy officials, and independent research. As outlined above, in the lead-by-example category, states could earn up to 2 points: 0.5 points each for energy savings targets in new and existing state buildings, benchmarking requirements for public facilities, ESPC activities, and fleet fuel efficiency mandates.

Many states demonstrate leadership in energy efficiency policy through the development of state energy plans. Often, governors will issue executive orders or form planning committees to evaluate state energy needs, goals, and opportunities. Sometimes, legislatures initiate the process. These actions are an important part of establishing a statewide vision for energy use. Recently, California, the District of Columbia, Hawaii, Iowa, Maine, Massachusetts, Michigan, Mississippi, Missouri, Montana, Nebraska, Nevada, New Jersey, New Mexico, New York, North Carolina, Rhode Island, South Carolina, and Vermont completed such plans or began the process for their development.[57] We do not award points purely on the basis of the development of a state energy plan, but we do consider the formal executive orders and policies that execute energy efficiency initiatives included in such plans. Table 35 presents states' scores for lead-by-example initiatives.

Table 35. State scoring on lead-by-example initiatives

State	New and existing state building requirements	Benchmarking requirements for public building	ESPC policy and programs	Efficient fleets	Score (2 pts.)
California	•	•	•	•	2
Connecticut	•	•	•	•	2
Delaware	•	•	•	•	2
Illinois	•	•	•	•	2
Minnesota	•	•	•	•	2
Montana	•	•	•	•	2
New Mexico	•	•	•	•	2
North Carolina	•	•	•	•	2
Texas	•	•	•	•	2
Utah	•	•	•	•	2
Washington	•	•	•	•	2
Vermont	•	•	•	•	2

[57] For more information on states with active energy plans, visit the National Association of State Energy Officials' website, www.naseo.org/stateenergyplans.

State	New and existing state building requirements	Benchmarking requirements for public building	ESPC policy and programs	Efficient fleets	Score (2 pts.)
Massachusetts	•	•	•	•	2
New Hampshire	•	•	•	•	2
Rhode Island	•	•	•	•	2
Tennessee	•	•	•	•	2
Colorado	•	•	•	•	2
Arkansas	•	•	•		1.5
Georgia	•	•	•		1.5
Hawaii		•	•	•	1.5
Kansas	•	•	•		1.5
Kentucky	•	•	•		1.5
Maine	•		•	•	1.5
Maryland	•	•	•		1.5
Michigan	•	•	•		1.5
Mississippi		•	•	•	1.5
Missouri	•		•	•	1.5
Nevada	•	•	•		1.5
New York	•	•	•		1.5
Oregon	•	•	•		1.5
Puerto Rico	•	•	•		1.5
South Carolina	•	•	•		1.5
Wisconsin	•		•	•	1.5
District of Columbia	•	•		•	1.5
Alabama			•	•	1
Alaska	•	•			1
Arizona	•		•		1
Florida			•	•	1
Iowa	•	•			1
Louisiana	•		•		1
New Jersey		•	•		1
Pennsylvania	•		•		1
Ohio		•	•		1
Virginia		•	•		1
Guam		•			0.5

State	New and existing state building requirements	Benchmarking requirements for public building	ESPC policy and programs	Efficient fleets	Score (2 pts.)
Idaho			•		0.5
Indiana	•				0.5
Nebraska		•			0.5
South Dakota		•			0.5
US Virgin Islands			•		0.5
Wyoming			•		0.5
Oklahoma					0
West Virginia					0
North Dakota					0

Leading and Trending States: Lead-by-Example Initiatives

Connecticut. As part of a goal to reduce state facilities' energy consumption by 20% by 2018 (CGS §16a-37u), Connecticut state agencies must establish an energy baseline, identify energy savings opportunities, and implement energy efficiency measures. The state requires the Department of Energy and Environmental Protection (DEEP) to benchmark and publicly disclose the energy and water consumption of state-owned or -operated buildings of 10,000 square feet or more. To date, staff members have benchmarked more than 40% of state buildings. To help with these efforts, the Institute for Sustainable Energy (ISE) runs a benchmarking help desk, providing towns, state agencies, and schools training and technical assistance on benchmarking and the use of ENERGY STAR Portfolio Manager. Connecticut also recently tightened its High Performance Building Performance Standard, which now requires state construction and renovation projects to achieve a score of 75 or more on EPA's ENERGY STAR Target Finder tool.

Vermont. In 2015, Governor Raimondo signed Executive Order 15-17, establishing the Lead by Example program within the state's Office of Energy Resources (OER) to oversee efforts to reduce energy consumption and GHG emissions in state facilities. This executive order also requires state agencies to reduce energy consumption by 10% by FY 2019, from a 2014 baseline. OER must establish interim goals, publicly disclose state energy data, and provide agencies with technical assistance. The state also set the goal that at least 25% of new light-duty fleet purchases and leases be zero-emissions vehicles by 2025.

Utah. In 2015, the Utah State Legislature enacted a requirement that all state buildings annually report their utility expenditures, energy and water consumption, and cost information at the building level. Each state agency must develop strategies for improving energy efficiency and designate a staff member responsible for coordinating these efforts. The State Building Board sends annual progress reports to the governor and the legislature. In addition, the state provides performance contracting technical support to public entities through a list of prequalified ESCOs, a list of prequalified third-party ESCO service reviewers, and the reinstatement of the Utah Chapter of the Energy Services Coalition.

Minnesota. Over the past decade, the state of Minnesota has shown its commitment to sustainable buildings by providing leadership, setting high performance standards, and implementing an integrated framework of programs that provide a comprehensive system for designing, managing, and improving building energy performance. Beginning with aggressive standards for state buildings based on the long-term goal of having a zero-carbon building stock by 2030, the state offers a complementary benchmarking program for tracking energy use and provides technical, contractual, and financial performance contracting assistance to public entities through its Office of Guaranteed Energy Savings Program. Additionally, new on-road vehicles must have a fuel efficiency rating that exceeds 30 mpg for city usage and 35 mpg for highway usage.

Kentucky. With almost $800 million in ESPC investments since enabling legislation in 1996, Kentucky has one of the largest performance contracting industries in the nation. Through the Local Government Energy Retrofit Program, the Kentucky Department for Energy Development and Independence is working with the Kentucky Department for Local Government to facilitate energy efficiency in smaller municipalities through ESPC. All state-supported universities and colleges in the state community and technical college system have ESPCs. The state also tracks real-time energy savings in state buildings and makes these data publicly available through the Kentucky Energy Dashboard. To date, the Commonwealth Energy Management and Control System (CEMCS) accounts for 164 buildings and more than 10 million square feet of state buildings. CEMCS was one of the few state government programs granted an increase in the current biennium so that more buildings could be included.

Research and Development

Research and development (R&D) programs drive advances in energy-efficient technologies, and states play a unique role in laying the foundation for such progress. By leveraging resources in the public and private sectors, state government programs can foster collaborative efforts and rapidly create, develop, and commercialize new energy-efficient technologies. These programs can also encourage cooperation among organizations from different sectors and backgrounds to further spur innovation.

Not only do state R&D efforts provide a variety of services to create, develop, and deploy new technologies for energy efficiency, but they address a number of failures in the energy services marketplace that impede the diffusion of new technologies (Pye and Nadel 1997). In response to the increasing need for state initiatives in energy-related R&D, several state bodies established the Association of State Energy Research and Technology Transfer Institutions (ASERTTI) in 1990. ASERTTI members collaborate on applied R&D and share technical and operational information, emphasizing end-use efficiency and conservation.

Aside from those institutions affiliated with ASERTTI, numerous other state-level entities (including universities, state governments, research centers, and utilities) fund and implement R&D programs to advance energy efficiency throughout the economy. Such programs include research on energy consumption patterns in local industries and the development of energy-saving technologies at state or university research centers and through public–private partnerships.

Individual state research institutions provide expertise and knowledge that policymakers can draw from to advance successful efficiency programs. These institutions enable valuable knowledge spillover to other states through information sharing—facilitated through ASERTTI membership—that allows states to benefit from one another's research. States without R&D institutions can use this shared information as a road map to begin or advance their own efficiency programs. Even leading states can improve or add to their R&D efforts by drawing from other states' programs and best practices.

SCORES FOR RESEARCH AND DEVELOPMENT

We reviewed state energy efficiency R&D institutions based on information collected from a survey of state energy officials and other, secondary research. This research complemented information we previously collected from the *National Guide to State Energy Research Centers* (ASERTTI 2012). In scoring this metric, we awarded 0.5 points for each major state government-funded R&D program dedicated to energy efficiency—including programs administered by state government agencies, public–private partnerships, and university programs—up to a maximum of 1 point. To ensure that scores more effectively credit state-administered, privately financed energy efficiency incentives, we shifted 0.5 points from the R&D metric to the state financial incentives metric. Because R&D funding often fluctuates, and it is difficult to determine the dollar amount that specifically supports energy efficiency, we do not currently score R&D based on program funding or staffing levels.[58] We recognize

[58] Institutions that focus primarily on renewable energy technology or alternative-fuel R&D do not receive credit in the *Scorecard*. In addition, programs that serve primarily an educational or policy development purpose also do not receive points.

that the presence of an R&D institution does not guarantee the deployment of technologies being developed or the achievement of actual energy savings. In future *State Scorecards*, we will seek ways to refine this metric through additional quantitative data.

Table 36 presents the results. For expanded descriptions of state energy efficiency R&D program activities, visit ACEEE's State and Local Policy Database (ACEEE 2016).

Table 36. Scoring on R&D institutions with energy efficiency-focused research

State	R&D institutions	Score (1 pt.)
California	The California Energy Commission's Electric Program Investment Charge (EPIC) Program and Natural Gas Research and Development Program, University of California-Davis's Energy Efficiency Center, University of California-Berkeley's Center for the Built Environment, University of California-Irvine's California Plug Load Research Center, and University of California-Los Angeles's Center for Energy Science and Technology Advanced Research and Smart Grid Energy Research Center	1
Colorado	Colorado State University's Engines and Energy Conversion Lab and Institute for the Built Environment, University of Colorado-Boulder's Renewable and Sustainable Energy Institute, Colorado School of Mines' Research in Delivery, Usage, and Control of Energy, Colorado Center for Renewable Energy Economic Development, and Colorado Energy Research Collaboratory	1
Florida	University of Central Florida's Florida Solar Energy Center, Florida State University's Energy and Sustainability Center, University of Florida's Florida Institute for Sustainable Energy and Florida Energy Systems Consortium, University of South Florida's Clean Energy Research Center, and University of West Florida's Community Outreach, Research and Education	1
Illinois	University of Illinois at Chicago's Energy Resources Center, The Illinois Sustainable Technology Center, University of Illinois Urbana-Champaign Department of Urban and Regional Planning, and University of Illinois Urbana-Champaign Smart Energy Design Assistance Center	1
Minnesota	Conservation Applied Research and Development Program, Center of Diesel Research at the University of Minnesota, Center for Sustainable Building Research, and the Center for Energy and Environment's Innovation Exchange	1
Nebraska	The Nebraska Center for Energy Sciences Research, the Energy Savings Potential program, and University of Nebraska Utility Corporation	1
New York	The New York State Energy Research and Development Authority, State University of New York's Center for Sustainable & Renewable Energy, Syracuse University's Building Energy and Environmental Systems Laboratory, City University of New York's Institute for Urban Systems, and Albany State University's Energy and Environmental Technology Application Center (E2TAC)	1
North Carolina	The North Carolina Solar Center, North Carolina A&T State University's Center for Energy Research and Technology, and Appalachian State University's Energy Center	1

State	R&D institutions	Score (1 pt.)
Oregon	The Oregon Built Environment and Sustainable Technologies Center, University of Oregon's Energy Studies in Building Laboratory and Baker Lighting Lab, Portland State University's Renewable Energy Research Lab, the Energy Trust of Oregon, and the Oregon Transportation Research and Education Consortium	1
Pennsylvania	Leigh University's Energy Research Center, Penn State's Indoor Environment Center, and the Consortium for Building Energy Innovation	1
Arizona	The Sustainable Energy Solutions Group of Northern Arizona University and Arizona State University's LightWorks Center	1
Connecticut	The University of Connecticut's Fraunhofer Center for Energy Innovation and the Connecticut Center for Advanced Technology	1
Georgia	The Southface Energy Institute and the Georgia Institute of Technology's Brook Byers Institute for Sustainable Systems	1
Iowa	The Iowa Energy Center, with research support through the Iowa Economic Development Authority	1
Kansas	Studio 804, Inc. and Wichita State University's Center for Energy Studies	1
Maryland	University of Maryland's Energy Research Center and the Maryland Clean Energy Technology Incubator	1
Massachusetts	The Massachusetts Energy Efficiency Partnership and the University of Massachusetts-Amherst's Center for Energy Efficiency and Renewable Energy	1
Missouri	Midwest Energy Efficiency Research Consortium, the National Energy Retrofit Institute, and the Missouri University of Science and Technology's Energy Research and Development Center	1
Tennessee	University of Tennessee partnerships with Oak Ridge National Laboratory and the Electric Power Research Institute, the Center for Ultra-Wide-Area Resilient Electric Energy Transmission Networks, the Center for Manufacturing Research at Tennessee Technological University, and the Institute for Advanced Composites Manufacturing Innovation	1
Texas	Texas A&M's Engineering Experiment Station and the University of Texas-Austin's Center for Energy and Environmental Resources	1
Utah	Utah State University and the Alliance for Computationally-guided Design of Energy Efficiency Electronic Materials (CDE3M)	1
Virginia	Southern Virginia Product Advancement Center and the R&D Center for Advanced Manufacturing and Energy Efficiency	1
Delaware	University of Delaware's Center for Energy and Environmental Policy, University of Delaware's Mid-Atlantic Industrial Assessment Center (IAC). and Delaware Technical and Community College Energy House and Center for Energy Education and Training, Sustainable Energy Training Center, and Trane Center of Excellence	1
Wisconsin	The Energy Center of Wisconsin, Wisconsin Focus on Energy, and the University of Wisconsin's Solar Energy Lab	1
Puerto Rico	Puerto Rico Energy Center and the National Institute for Islands Energy and Sustainability	1

State	R&D institutions	Score (1 pt.)
Washington	Smart Buildings Center, Washington State University Energy Program	1
Kentucky	University of Louisville's Conn Center for Renewable Energy Research	0.5
Alabama	University of Alabama's Center for Advanced Vehicle Technologies	0.5
Alaska	The Cold Climate Housing Research Center	0.5
District of Columbia	Green Building Fund Grant Program	0.5
Hawaii	The Hawaii Natural Energy Institute at the University of Hawaii	0.5
Idaho	The Center for Advanced Energy Studies	0.5
Indiana	Purdue University Energy Efficiency and Reliability Center	0.5
Maine	Maine Technology Institute (MTI)	0.5
Mississippi	Mississippi State University's Energy Institute	0.5
Nevada	The Center for Energy Research at University of Nevada-Las Vegas	0.5
New Jersey	The Edison Innovation Clean Energy Fund	0.5
Ohio	Ohio State University's Center for Energy, Sustainability, and the Environment	0.5
Rhode Island	Sustainable Energy Program at the URI Outreach Center	0.5
Vermont	University of Vermont Smart Grid Research Center	0.5
West Virginia	West Virginia University Energy Institute	0.5

We describe several successful R&D initiatives in greater detail below. Refer to ACEEE's State and Local Policy Database for more information on all the programs listed above.

Leading and Trending States: State Research and Development Initiatives

Colorado. The state of Colorado demonstrates leadership in several areas of energy efficiency. Colorado State University, the University of Colorado, and the Colorado School of Mines each has research centers and facilities dedicated to developing energy efficiency and clean energy technologies. The Center for Renewable Energy Economic Development also plays a major role in Colorado's energy efficiency activities by promoting and supporting new clean-tech companies throughout the state.

Delaware. The University of Delaware has several centers that conduct energy efficiency-related research. The Mid-Atlantic Industrial Assessment Center (IAC) provides energy, waste, and productivity assessments to small and midsized manufacturers with a concentration in energy efficiency. Since its creation, IAC has provided energy efficiency recommendations to more than 100 clients, achieved 10–30% energy bill reductions, and been recognized by the US Department of Energy as a "Center of Excellence." Faculty and research staff at the Center for Energy and Environmental Policy conducts research on sustainable energy utilities and clean energy futures. In addition, Delaware Technical and Community College recently opened energy efficiency workforce development centers at three of its campuses.

Florida. Florida's universities host a wide array of energy efficiency research, investing more than $5 million in the institutions that lead this work. The University of Florida's Florida Institute for Sustainable Energy performs research on efficient construction and lighting and has more than 150 faculty members at 22 energy research centers. The University of Central Florida's Florida Solar Energy Center focuses on energy-efficient buildings, schools, and standards and has a similarly large faculty. The state created the Florida Energy Systems Consortium to bring universities together to share their energy-related expertise. Twelve universities participate in the working group, conducting R&D on innovative energy systems that lead to improved energy efficiency and expanded economic development for the state.

New York. The New York State Energy Research and Development Authority (NYSERDA) supports a broad range of technology research, development, and commercialization activities to improve the energy efficiency and expand the energy options for the buildings, industrial, transportation, power, and environmental sectors of the New York economy. NYSERDA invests in scientific research, market analysis, product development, and technology field validation. These investments provide knowledge on the environmental impacts of current and emerging energy options, conduct early-stage market analysis associated with new technologies, advance clean energy innovations towards market readiness, and stimulate innovation.

POSSIBLE NEW METRICS

During the data collection process for the *2016 State Scorecard*, we examined a variety of new metrics that could more accurately and comprehensively reflect state efforts to improve energy efficiency across sectors. This year, we attempted to refine our analysis of financial incentives by collecting data on state budgets for incentives and financing programs, participation rates, verified energy savings, dollar savings, and the leveraging of private capital. To collect these data, we relied on our requests to state energy offices. We tried to collect enough information for each potential metric to include it in our analysis, but the data we received were not robust enough to include. For example, 24 states provided data on savings from incentives and financing programs—up from 14 states in 2015, but savings data were generally program specific rather than portfolio wide, and in several cases savings were projected rather than verified. States often provided budget data at the agency level and reported participation rates without including the number of eligible customers. For a summary of quantitative data received in 2016 for state financial incentives, performance contracting, and public building energy benchmarking, see Appendices H–J. We will continue to solicit data from states on these potential metrics and refine our financial incentives scoring methodology in the future based on data availability.

Energy Efficiency Financing

To an increasing degree, states are leveraging private capital alongside public dollars to incentivize energy efficiency. Green banks, for example, combine public and ratepayer funds to stimulate private investments in clean energy projects. State or local governments typically create these financing institutions and often provide technical assistance alongside financing products (Gilleo, Stickles, and Kramer 2016).[59] PACE financing is another increasingly popular public–private partnership model for which we now give credit.

One of the obstacles to measuring private energy efficiency financing's success is the absence of protocols for measuring and verifying energy savings. Nonratepayer programs—public and private alike—often have less rigorous EM&V protocols than utility-run programs. In addition, private institutions offering these financing tools often do not prioritize the collection of energy savings data. While we have begun to credit such incentives in a qualitative way when they are appropriately funded, we will continue to solicit quantitative data from states to better understand these programs' effectiveness.

Energy Efficiency Programs for Low-Income Households

Low-income households often face a disproportionate energy burden that can be alleviated by energy efficiency (Drehobl and Ross 2016). Reducing energy bills for low-income households not only keeps money in these families' pockets, but it also improves their quality of life by creating healthier homes and neighborhoods. These efforts can help states address other priorities such as reduced emissions, economic development, and improved public health.

Energy efficiency programs for low-income households can be funded through federal, state, or ratepayer dollars and delivered by utilities, state housing finance agencies, community action agencies, or other agencies and organizations. State Energy Offices (SEOs) have many options for investing in energy efficiency in low-income communities, including but not limited to the following:

- Design energy efficiency programs or incentives specifically for low-income communities and consider investing state resources alongside federal and ratepayer dollars.
- Leverage existing Weatherization Assistance Program delivery channels to expand energy efficiency offerings to program participants

[59] While we do credit evaluated savings from financing programs (including on-bill financing programs) in the utilities chapter, in this chapter we recognize financing programs, such as green banks, that leverage additional nonratepayer state resources.

- Provide technical assistance and financial resources to public housing authorities as they work with ESCOs to improve their properties
- Encourage agencies and organizations allocating federal grants, such as the Low Income Housing Tax Credit, to prioritize energy efficiency in their allocation process

Through ongoing research and outreach, ACEEE is working to help states and utilities identify the challenges and opportunities in serving this underserved market. We hope to recognize state efforts and identify best practices in future *State Scorecards*. Moving forward, we will work to collect additional data on state energy efficiency efforts in low-income communities, identify best practices, and refine metrics for crediting state initiatives in this sector. Below, we highlight several examples of states that have enacted policies or programs for low-income communities.

Leading and Trending States: Low-Income Energy Efficiency Policies and Programs

Wyoming. The state's housing finance agency—Wyoming Community Development Authority (WCDA)—offers its Energy Savers Loan to income-qualified existing residential single family homes. WCDA offers loan recipients up to $15,000 for home rehabilitation services, including health and safety repairs, building envelope upgrades, and other energy efficiency improvements (WCDA 2015).

Virginia. To support energy efficiency projects in its Low-Income Housing Tax Credit (LIHTC) allocation process, the Virginia Housing Development Authority (VHDA) provides a scoring incentive for applicants pursuing green certification standards such as Leadership in Energy and Environmental Design (LEED) or EarthCraft. The EarthCraft Multifamily program certifies both newly constructed and renovated projects that classify as either affordable or market rate. In Virginia, all successful applicants for LIHTC have committed to meeting EarthCraft Multifamily standards. A recent evaluation of actual utility usage data in 15 LIHTC properties in Virginia found that units certified to EarthCraft Multifamily high energy efficiency standards achieved an average annual savings of 5,568 kWh and $648, with over 40% less energy consumption than in standard housing (EarthCraft Virginia).

Connecticut. The Connecticut Green Bank recently launched a partnership with the Housing Development Fund to provide loans and technical assistance to affordable multifamily building owners interested in energy efficiency improvements and clean energy projects. Funded with a $5 million grant from the MacArthur Foundation, the program will finance energy efficiency upgrades and health and safety remediation measures in eligible properties (The Commercial Record 2016). Connecticut Green Bank is a quasi-public organization created by the state legislature in 2011 as the nation's first green bank. Funding for energy efficiency comes primarily from a system benefit charge, RGGI auction proceeds, and ARRA funds.

Chapter 7. Appliance and Equipment Efficiency Standards

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INTRODUCTION

Every day, we use appliances, equipment, and lighting in our homes, offices, and public buildings. While the energy consumption and cost for a single device may seem small, the extra energy consumed by less efficient products collectively adds up to a substantial amount of wasted energy. For example, a single computer might waste a small amount of electricity, but the energy wasted by millions of computers in the United States is considerable. Real and persistent market barriers inhibit sales of more efficient models to consumers. Appliance efficiency standards overcome these barriers by initiating change in the manufacturer's—not the consumer's—actions, requiring manufacturers to meet minimum efficiency levels for all products and thereby removing the most inefficient products from the market.

States have historically led the way when it comes to establishing standards for appliances and other equipment. In 1976, California became the first state to introduce appliance standards. Many others, including New York and Massachusetts, soon followed. The federal government did not establish any national standards until Congress passed the National Appliance Energy Conservation Act of 1987, which included standards based on those adopted by California and several other states. Congress enacted additional national standards in 1988, 1992, 2005, and 2007. In general, these laws set initial standards for products and require the DOE to review and strengthen standards for specific products. Approximately 55 products are now subject to national efficiency standards.

President Ronald Reagan signed the original national appliance standards into law in 1987; by 2015, savings from such standards had grown to 13% of electricity consumption and 4% of natural gas usage. Appliance standards saved enough energy in 2015 to meet the electricity needs of 43 million homes (more than one-third of US households) and the gas needs of about 10 million US homes. By 2030, the savings will grow to 20% of projected electricity consumption and 6% of gas usage, as new national standards take effect and the impact of existing standards grows.[60]

In 2030, the carbon dioxide emissions reductions from standards completed since 2007 will reach about 220 million metric tons. This amounts to about one-quarter of the emissions reductions expected from the Clean Power Plan, the Obama Administration's highest profile action to reduce climate emissions.

Historically, there has been an inverse relationship between standards activity at the federal and state levels. When federal activity picks up, the impetus for states to set standards decreases, and vice versa. In recent years, the DOE has been very active and only a handful of states have proposed or adopted standards. California remains the most engaged, with a full slate of standards and labeling regulations in process, pending, or on deck. After adopting standards for deep-dimming fluorescent ballasts and updating toilet, faucet, and

[60] Appliance Standards Awareness Project (ASAP) unpublished update to Lowenberger et al. 2012.

urinal standards in 2015, the California Energy Commission (CEC) adopted new standards in 2016 for LEDs, small-diameter directional lamps, and showerheads.

Other states have also taken steps. Colorado updated its plumbing products standards, having adopted new standards for toilets in 2014. Legislators in Rhode Island and Washington filed bills this year to add standards for products such as faucets, toilets, urinals, deep-dimming fluorescent ballasts, and air purifiers. We expect more states to consider adopting standards once the standards for the products in the California pipeline are finalized.

Federal preemption generally prevents states from setting standards stronger than existing federal requirements for a given product. States that wish to implement their own standards after federal preemption must apply for a waiver; however states remain free to set standards for any products that are not subject to national standards. These additional standards can have significant energy efficiency benefits and set precedents for adopting new national standards.

SCORING AND RESULTS

We updated the scoring methodology for appliance and equipment standards this year to emphasize savings from recent state actions. States could earn up to 2 points for appliance efficiency standards not presently preempted by federal standards and for which the effective date (not the adoption date) for *any* state is either within the past three calendar years or in the future.[61] This methodology credits recent state action, provides an incentive for states to adopt new standards, and deemphasizes older state standards, some of which were garnering little to no savings. Giving credit to all states that have adopted a standard for which the most recent effective date is within the past three years acknowledges the important role early adopters play in paving the way for other states to adopt similar standards.

For example, California adopted the first state battery charger standards in 2012 (effective in 2013), followed by Oregon in 2013 (effective in 2014). Both states get credit for battery charger standards in 2016 because the most recent effective date (2014) is within the past three years. Similarly, both states will still get credit for these standards in 2017. Assuming no additional states pass battery charger standards, we will not count battery charger savings in 2018 since no compliance dates will be within three calendar years.

We calculated the scores based on cumulative per capita savings (measured in Btus) through 2030. We used a floating start date that aligns with each state's product compliance date. For example, standards for deep-dimming fluorescent ballasts took effect in California in 2016. Our savings analysis for that product in California covers the period from 2016 to 2030. If another state adopts the same standards with a later effective date, the analysis will begin in the year the standards take effect in that state.

[61] The effective date is also known as the *compliance date*.

If states adopt different standards or tiers for one product, then we consider each standard separately. For example, California set new standards for faucets in 2015 that are more stringent than the standards Colorado adopted. We consider each a separate standard.

We estimated savings using the bottom-up approach of previous analyses of savings from appliance standards conducted by the Appliance Standards Awareness Project (ASAP) and ACEEE (Lowenberger et al. 2012). We used estimates of annual shipments, per-unit energy savings, and average product lifetime based on the best available data. To estimate state-by-state shipments, we allocated national shipments to individual states in terms of households for residential products and population for commercial products. We also accounted for the portion of sales that had already met the standard level at the time the first state standard was established for a given product.

We normalized the savings estimates using the population of each state in order to rank states based on per-capita energy savings. We scored in 0.5-point increments up to a maximum of 2 points.

Table 37 shows the scoring methodology, and table 38 shows the results.[62]

Table 37. Scoring of savings from appliance standards

Energy savings through 2030 (MMBtu/capita)	Score
45 or more	2
30–44.99	1.5
15–29.99	1
0.1–14.99	0.5
No energy savings	0

Table 38. State scoring for appliance efficiency standards

State	Energy savings through 2030 (MMBtu/capita)	Date most recent standards adopted	Score (2 pts.)
California	48.1	2015	2
Oregon	16.4	2011	1
Connecticut	9.1	2011	0.5
Colorado	5.8	2014	0.5

Scoring the maximum of 2 points, California continues to lead on appliance efficiency standards, most recently setting standards for LEDs and small-diameter directional lamps and updating standards for showerheads and faucets. Rulemaking proceedings are ongoing for computers, monitors, signage displays, pool pump motors, and portable electric spas.

[62] Earlier editions of the *Scorecard* mistakenly reported figures in table 37 as Bbtus rather than MMBtus.

Not only has California adopted the greatest number of standards, but many other states' standards are based on California's. Oregon earned credit for battery chargers and TV standards, Connecticut for TV standards, and Colorado for faucets and showerhead standards.

Because we updated our methodology this year to place more emphasis on recent activity, we did not give credit to a number of states that earned credit for standards in last year's *Scorecard*.[63] Many of these states adopted standards during a flurry of state activity between 2004 and 2009 for products such as water dispensers, spas, and pool pumps. A DOE rulemaking for pool pump standards is now underway, thanks in large part to the groundwork laid by many of these states.

Over the past five to six years, the drought-prone states of California, Colorado, Georgia, and Texas adopted standards for faucets, showerheads, toilets, and urinals and are on track to save a significant amount of water. The faucet and showerhead standards will also save energy by reducing hot-water consumption.

Leading and Trending States: Appliance and Equipment Efficiency Standards

California. The 1974 Warren–Alquist Act granted the California Energy Commission (CEC) the first-in-the-nation authority to adopt appliance and equipment efficiency standards. Since that time, California has adopted standards for more than 100 products, many of which have subsequently become federal standards. For more details on CEC standards, see 2015 CEC Appliance Efficiency Regulations, published on July 1, 2015.

CEC adopted additional standards not included in the 2015 regulations. In late 2015, they approved a new package of standards and labeling and reporting requirements for HVAC air filters, fluorescent dimming ballasts, heat pump water chilling packages, faucets, toilets, and urinals. In April 2016, CEC updated showerhead standards and adopted the first-ever state standards for LEDs and small-diameter directional lamps. CEC is conducting ongoing rulemakings for computers, monitors and displays, pool pump motors, and portable electric spas.

Oregon. Beginning in 2002, Oregon introduced several appliance standards bills, passing one in 2007 and another in 2013. With the signing of Senate Bill 692 in June 2013, Oregon added three new standards to its books—consumer battery chargers, televisions, and double-ended quartz halogen lamps. Oregon now has eight nonpreempted standards, second only to California.

[63] The states include Arizona, Georgia, Maryland, New Hampshire, Rhode Island, Texas, and Washington. The District of Columbia also falls into this category.

Chapter 8. Conclusions

In the past year, many states continued to push the needle on energy efficiency by increasing support for existing programs. They also looked for new ways to expand their menu of efficiency measures and leverage the power of private markets. The benefits of these efforts are diverse and abundant; they include boosting economic development in the energy efficiency services and technology industries, saving money for consumers, and strengthening environmental sustainability through pollution reductions.

States today are tackling energy efficiency amid a rapidly changing environment rife with countervailing conditions, including aging infrastructure, advances in data access, and competition from customer-sited distributed energy resources. In an effort to manage these challenges and opportunities, states are undertaking large-scale changes in rate structures, utility business models, and regulatory frameworks. The potential of private market forces to deliver energy efficiency—by using financing as a complement to or even a substitute for traditional programs—continues to interest those looking to shape the utility of the future. Integrating these efforts with ratepayer funded programs also has become an increasingly hot topic, as has the role and structure of the monopoly investor-owned utility. States such as New York and Minnesota are undergoing dramatic utility restructuring, while Connecticut and Hawaii increasingly look to financing from green banks to deliver energy efficiency; the latter states do so amid surging efforts from the Green Bank Network and other groups to standardize processes and build investor confidence. To facilitate this transition and attract investors, improving the availability of information, education, and loan performance data will be key.

Amid this experimentation, we continue to see energy efficiency deliver big savings and a variety of benefits. Energy savings continue to rise, with states in the Northeast proving that electricity savings of 2%—and even upwards of 3%—are possible. In California, meanwhile, new strategies to fund energy efficiency programs yielded impressive results over the past year to raise the state's ranking as an energy saver. And, all across the country, states are increasingly emphasizing energy efficiency's role in resilience efforts, be it through CHP, lower peak load, or more durable and sustainable buildings.

This year's *State Scorecard* also emphasizes the need to consistently update energy efficiency policies and programs to both embrace advancements and bolster existing policy goals. A growing number of states (about 25%) have taken major steps toward adopting the most recent iteration of building codes, for example. However, with deadlines for code certification statements looming in 2016 and 2017, other states will likely follow suit; adopting these codes sooner rather than later will ultimately increase the resulting energy savings.

In this year's *State Scorecard*, a wide gap remains between states near the top and those at the bottom of the rankings. A regulatory environment that levels the playing field for energy efficiency—the fastest, cheapest, cleanest energy resource—is critical to capturing the full range of its benefits for states and for consumers.

Energy efficiency programs advanced in several states in 2016. New Hampshire approved its first-ever EERS this past summer. Other states extended energy savings targets for utilities, finalizing long-term visions that will ensure large-scale savings in future years. For example, both Massachusetts and Connecticut approved three-year energy efficiency plans pledging more aggressive savings targets for 2016–2018. In the fall of 2015, California passed two game-changing pieces of legislation: Senate Bill 350, requiring a doubling of energy efficiency savings from electricity and natural gas end-uses by 2030, and Assembly Bill 802, which promotes building benchmarking and enables access to whole-building data for buildings above a certain size. Other states committing to extend their efficiency goals included Arkansas and Maryland. Meanwhile, Delaware continued to lay the groundwork for a potential future EERS.

While the utility sector continues to serve as the primary avenue through which states seek to advance energy efficiency, there are clear signs that state governments will increasingly look to leverage private capital to fund and deliver energy efficiency programs to consumers. Green banks are now well established in Connecticut and New York, and many other states are following suit. Other financing options, such as residential and commercial PACE, are also continuing to gain traction. Over the next few years, states will be seeking a balance between these financing programs and more traditional ratepayer-funded programs. Ultimately, both private financing solutions and ratepayer-funded energy efficiency programs deliver important energy savings options to the market.

States are also responding to an uncertain federal regulatory landscape. The EPA's Clean Power Plan, pending judicial review, could drive substantial additional investment in energy efficiency as a compliance path for meeting GHG emissions mandates. Low-income communities are a particularly important area of focus given the CPP's Clean Energy Incentive Program, which rewards states for spurring energy efficiency in disadvantaged neighborhoods. While uncertainty remains about the CPP's future following the February Supreme Court stay, there been no change to the EPA's legal requirement to regulate carbon dioxide, and energy efficiency programs will likely continue to offer the most cost-effective way for states to demonstrate compliance.

Energy efficiency can save consumers money, drive investment across many economic sectors, and create jobs. Several states are consistently leading the way on energy efficiency and many more are notably increasing their efforts. Still, many opportunities to sustain and expand current efforts remain. Energy efficiency is a resource that is abundant in every state. Reaping its full economic, energy security, and environmental benefits will require continued leadership from all stakeholders, including legislators, regulators, and the utility industry.

DATA LIMITATIONS

The scoring framework we used in this report is our best current attempt to represent the myriad efficiency metrics as a quantitative score. Any effort to convert state spending data, energy savings data, and adoption of best-practice policies across six policy areas into one state energy efficiency score has obvious limitations. Here, we suggest a few areas for future research that will help refine the *State Scorecard* scoring methodology and more accurately represent the changing landscape of energy efficiency in the states.

One of the most pronounced limitations is access to recent, reliable data on the results of energy efficiency work. Because many states do not gather data on the performance of energy efficiency policy efforts, we use a best-practices approach to score some policy areas. As an example, it is difficult to score states on building energy code compliance rates because the majority of them do not collect the relevant data. This year, we attempted to gather this information during the data collection process, but only about half of the states were able to provide quantitative data, and many of the results were only rough estimates. The current *Scorecard* expands our best-practices approach in this category, but performance metrics would allow for more objective and accurate assessment. While states should be applauded for adopting stringent building energy codes, the success of these codes in reducing energy consumption is unclear without a way to verify actual implementation.

As in the past, we face a similar difficulty in scoring state-backed financing and incentive programs for energy efficiency investments. Though many states have seemingly robust programs aimed at residential and commercial consumers, few are able to relay information on program budgets or energy savings resulting from such initiatives. As a result, we can offer only a qualitative analysis of these programs. This lack of quantitative data is becoming increasingly pronounced as many states begin pouring financial resources into green banks. Without comparable results on dollars spent and rigorously evaluated energy savings, it is impossible to judge these programs with the same scrutiny as we judge utility programs.

We would also like to see spending and savings data for energy efficiency programs targeting home-heating fuel and propane. This year, we added questions to our data request asking for savings and spending attributable to efficiency efforts in these areas. Because only a few states responded to these particular queries, we could not include the data in this year's scoring methodology. However we will continue to examine workable metrics for fuel oil and propane efficiency in the future.

POTENTIAL NEW SCORECARD *METRICS*

We have described relevant potential future metrics or revisions to existing metrics in several chapters of this year's *State Scorecard*. While we believe our data collection and scoring methodology are comprehensive, there is always room for modifications. As the energy efficiency market continues to evolve and data become more available, we will continue to adjust each chapter's scoring metrics. Here, we present some additional metrics that currently fall outside the scope of our report but that nonetheless indicate important efficiency pathways.

State efficiency programs that fall outside utility-sector and public benefits programs are an area in which we continue to revise our data request; our goal is to find ways to transition to a more comprehensive and quantitative assessment. We hope to recognize state government and regulatory efforts to enable home and business owners to finance energy efficiency improvements through on-bill financing and other innovative incentive programs. One possible metric by which to compare state financial incentives is the level and sustainability of budgets for these programs. This information is available in some cases, but gathering it for all programs will continue to present challenges. We may also be able to compare state energy efficiency R&D efforts on the basis of budgets and staffing levels, but data availability is again an issue.

As discussed in Chapter 6, states are increasingly leveraging private capital through mechanisms such as green banks and PACE financing in an effort to harness the free market to fund energy efficiency and clean energy. Here, too, we would also like to expand the *Scorecard* to measure to the progress of these programs. For example, we would like to better capture efforts to combine public and ratepayer funds to stimulate private investments in clean energy projects. However, as mentioned, these efforts are currently impeded by the absence of protocols for measuring and verifying energy savings when it comes to private financing. Nonratepayer programs—public and private alike—often have less rigorous EM&V protocols than utility-run programs. So, while we currently credit these incentives, our ability to do so in a quantitative manner will depend on the quality of available energy savings data.

The effort to improve energy efficiency in low-income households is another area we would like to emphasize in the *State Scorecard*. Low-income households account for about one-third of the US population, yet data have shown that these communities are underrepresented in efficiency programs offered to all residential customers. Furthermore, recent ACEEE analysis has found that the percentage of household income that goes toward energy costs—also known as the *energy burden*—for low-income, African American, Latino, and renters is up to three times more than that of the average household. States that pursue investment in low-income energy efficiency programs in an effort to extend the health and quality of life benefits of energy efficiency to disadvantaged communities will receive added consideration in future *State Scorecards*.

Internet-connected devices, smart meters, and other intelligent efficiency technologies are proliferating in many states. These devices help overcome informational and motivational barriers to consumer uptake of energy efficiency. Similarly, a new industry is emerging that uses social marketing and social media to encourage consumers to save energy—such as by giving customers frequent feedback on their energy use and tailored energy savings tips. Data-focused policies—such as state data privacy policies, disclosure of building energy use, and data-access policies such as the industry-led Green Button standard—can help this promising energy efficiency area grow. The *State Scorecard* began collecting information on data-access policies in 2015 and continued to do so this year. Although we have yet to quantify progress on data access in a scoring methodology, given the rapid advances many states are making in this area, we intend to include it in our scoring next year.

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Appendix A. Respondents to Utility and State Energy Office Data Requests

State/territory	Primary state energy office data request respondent	Primary public utility commission data request respondent
Alabama	Susan Fleeman, Assistant to Division Chief, Alabama Energy Office	Patricia Smith, Manager, Electricity Policy Division Alabama Public Service Commission
Alaska	Katie Conway, Assistant Program Manager, Energy Efficiency and Conservation Program, Alaska Energy Authority	Anne Marie Jensen, Process Coordinator, Regulatory Commission of Alaska
Arizona	Jordan Hibbs, Consultant, Arizona Department of Administration	---
Arkansas	Blake Perry, Deputy Director, Arkansas Energy Office	Eddy Moore, Legal Adviser, Arkansas Public Utility Commission
California	Bill Pennington, Deputy Division Chief, Efficiency and Renewable Energy Division, California Energy Commission	Amy Reardon, Senior Regulatory Analyst, California Public Utility Commission
Colorado	---	---
Connecticut	Michele Melley, Associate Research Analyst, Connecticut Department of Energy and Environmental Protection	Michele Melley, Associate Research Analyst, Connecticut Department of Energy and Environmental Protection
Delaware	Jessica Quinn, Evaluation, Measurement, and Verification Project Manager, Delaware Department of Natural Resources and Environmental Control	Jessica Quinn, Evaluation, Measurement, and Verification Project Manager, Delaware Department of Natural Resources and Environmental Control
District of Columbia	Edward Yim, Associate Director of Policy & Compliance, District Department of the Environment	Ben Plotzker, Technical Energy Analyst, Vermont Energy Investment Corporation
Florida	April Groover Combs, Senior Management Analyst, Florida Department of Agriculture and Consumer Services	Tripp Coston, Economic Supervisor, Conservation, Florida Public Service Commission
Georgia	---	Jamie Barber, Energy Efficiency and Renewable Energy Manager, Georgia Public Service Commission
Hawaii	---	---
Idaho	Jennifer Pope, Senior Energy Specialist, Idaho Office of Energy Resources	---
Illinois	Deirdre Coughlin, Acting Energy Division Manager, Illinois Department of Commerce and Economic Opportunity	Jim Zolnierek, Director, Policy Division, Illinois Commerce Commission
Indiana	---	Carmen Pippenger, Senior Utility Analyst, Indiana Utility Regulatory Commission
Iowa	Adrienne Ricehill, Program Manager, Iowa Energy Office	Brenda Biddle, Utility Specialist, Iowa Utilities Board
Kansas	---	---

State/territory	Primary state energy office data request respondent	Primary public utility commission data request respondent
Kentucky	Lee Colten, Assistant Director, Kentucky Department for Energy Development and Independence	Bob Russell, Public Utilities Rates and Tariffs Manager, Kentucky Public Service Commission
Louisiana	Paul Miller, Director, Technology Assessment Division, Louisiana Department of Natural Resources	Donnie Marks, Utilities Administrator, Louisiana Public Service Commission
Maine	Lisa Smith, Senior Planner, Governor's Energy Office	Laura Martel, Research and Evaluation Manager, Efficiency Maine
Maryland	Rachel Weaver, Energy Program Manager, Maryland Energy Administration	Amanda Best, Assistant Director, Energy Analysis and Planning Division, Maryland Public Service Commission
Massachusetts	Lyn Huckabee, Residential Energy Efficiency Program Coordinator, Massachusetts Department of Energy Resources	Lyn Huckabee, Residential Energy Efficiency Program Coordinator, Massachusetts Department of Energy Resources
Michigan	Tania Howard, Community Energy Management Program Coordinator, Michigan Energy Office	Karen Gould, Staff, Energy Efficiency Section, Michigan Public Service Commission
Minnesota	Anthony Fryer, Conservation Improvement Program Coordinator, Minnesota Department of Commerce	Anthony Fryer, Conservation Improvement Program Coordinator, Minnesota Department of Commerce
Mississippi	Larissa Williams, Technical Assistance Manager, Mississippi Development Authority	Brandi Myrick, Director, Electric, Gas & Communications Division, Mississippi Public Utilities Staff
Missouri	Brenda Wilbers, Program Director, Division of Energy	John Rogers, Manager, Energy Unit, Resource Analysis Section, Missouri Public Service Commission
Montana	Garrett Martin, Senior Energy Analyst, Energy Efficiency & Compliance Assistance, Montana Department of Environmental Quality	Margo Schurman, Utility Policy Analyst, Montana Public Service Commission
Nebraska	Danielle Jensen, Public and Legislative Liaison, Nebraska Energy Office	Shelley Sahling-Zart, Vice President and General Counsel, Lincoln Electric System
Nevada	Kelly Thomas, Energy Program Manager, Governor's Office of Energy	Cristina Zuniga, Economist, Nevada Public Utility Commission
New Hampshire	Rebecca Ohler, Administrator, Technical Services Bureau, Department of Environmental Services, and Jim Cunningham, Utility Analyst, New Hampshire Public Utility Commission	Jim Cunningham, Utility Analyst, New Hampshire Public Utility Commission
New Jersey	Sherri Jones, Marketing Administrator, New Jersey Board of Public Utilities	Sherri Jones, Marketing Administrator, New Jersey Board of Public Utilities
New Mexico	Harold Trujillo, Bureau Chief, Energy Technology and Engineering, New Mexico Energy Office	Heidi Pitts, Utility Economist, New Mexico Public Regulatory Commission

State/territory	Primary state energy office data request respondent	Primary public utility commission data request respondent
New York	Allyson Burns, Program Manager, NYSERDA	Kanchana Paulraj, Utility Engineer, New York State Department of Public Service, and Allyson Burns, Program Manager, Reporting and Quality Assurance, NYSERDA
North Carolina	Russell Duncan, Program Manager, North Carolina Department of Environmental Quality	Jack Floyd, Engineer, Electric Division, Public Staff, North Carolina Utilities Commission
North Dakota	Andrea Holl Pfennig, Energy Outreach Program Administrator, North Dakota Department of Commerce	Sara Cardwell, Public Utility Analyst, North Dakota Public Service Commission
Ohio	Preston Boone, Energy Program Analyst, Ohio Department of Development	---
Oklahoma	Kylah McNabb, Energy Policy Advisor, Office of the Secretary of Energy & Environment	Kathy Champion, Regulatory Analyst, Oklahoma Corporation Commission
Oregon	Warren Cook, Manager, Energy Efficiency and Conservation, Oregon Department of Energy, and Erik Havig, Planning Section Manager, Oregon Department of Transportation	Warren Cook, Manager, Energy Efficiency and Conservation, Oregon Department of Energy, Jean-Pierre Batmale, Senior Utility Analyst, Oregon Public Utility Commission, and Allison Robbins Mace, Manager, Energy Efficiency Planning & Evaluation, Bonneville Power Administration
Pennsylvania	Libby Dodson, Energy Efficiency Programs, Department of Environmental Protection	Joseph Sherrick, Supervisor, Technical Utility Supervisor, Pennsylvania Public Utility Commission
Rhode Island	Rachel Sholly, Chief, Program Development, Rhode Island Office of Energy Resources	Todd Bianco, Principal Policy Associate, Rhode Island Public Utility Commission
South Carolina	---	---
South Dakota	Michele Farris, State Energy Manager, South Dakota Office of the State Engineer	Darren Kearney, Utility Analyst, South Dakota Public Utilities Commission
Tennessee	Alexa Voytek, Program Manager, Department of Environment and Conservation	Kyle Lawson, Manager, Tennessee Valley Authority
Texas	William (Dub) Taylor, Director, State Energy Conservation Office, Comptroller of Public Accounts	Amy Martin, Vice President Consulting, Frontier Associates
Utah	Shawna Cuan, Energy Efficiency and Programs Manager, Governor's Office of Energy Development	Carol Revelt, Executive Staff Director, Utah Public Service Commission
Vermont	Asa Hopkins, Director of Energy Policy and Planning, Vermont Department of Public Service	Asa Hopkins, Director of Energy Policy and Planning, Vermont Department of Public Service
Virginia	Barbara Simcoe, State Energy Program Manager, Virginia Division of Energy, Department of Mines, Minerals, and Energy	David Eichenlaub, Deputy Director, Division of Energy Regulation, Virginia State Corporation Commission

State/territory	Primary state energy office data request respondent	Primary public utility commission data request respondent
Washington	Tony Usibelli, Special Assistant to the Director for Energy and Climate Policy, Department of Commerce, and Karin Landsberg, Senior Policy Specialist, Department of Transportation	---
West Virginia	Tiffany Bailey, Energy Development Specialist, West Virginia Division of Energy	Michael Dailey, Utilities Analyst, West Virginia Public Service Commission
Wisconsin	Vanessa Durant, Grant Specialist, Public Service Commission of Wisconsin	Joe Fontaine, Program and Policy Analyst, Public Service Commission of Wisconsin
Wyoming	Sherry Hughes, Energy Efficiency Program Manager, Wyoming Business Council, State Energy Office	---
Virgin Islands	---	---
Puerto Rico	José Maeso, Executive Director, State Office of Energy Policy	---
Guam	Lorilee Crisostomo, Director, Guam Energy Office	---

Appendix B. Electric Efficiency Program Spending Per Capita

State	2015 electric efficiency spending ($million)	$ per capita
Vermont	54.4	86.90
Massachusetts	557.9	82.11
Rhode Island	82.9	78.48
Connecticut	173.9	48.43
Maryland	276.8	46.08
Iowa	113.3	36.27
Washington	256.9	35.83
Oregon	142.9	35.47
California	1,378.2	35.21
Maine	42.5	31.97
Minnesota	151.5	27.59
Arkansas	76.1	25.55
Hawaii	33.3	23.28
Illinois	286.4	22.27
District of Columbia	13.9	20.62
New Jersey	177.6	19.83
Idaho	32.7	19.75
New Hampshire	25.6	19.24
New York	375.7	18.98
Michigan	188.0	18.94
Utah	55.9	18.66
Oklahoma	70.2	17.94
Pennsylvania	217.2	16.97
Indiana	111.7	16.87
Missouri	102.3	16.82
New Mexico	34.3	16.45
Colorado	87.6	16.06
Nevada	45.4	15.70

State	2015 electric efficiency spending ($million)	$ per capita
Arizona	105.0	15.38
Ohio	171.9	14.80
Wisconsin	79.8	13.83
North Carolina	113.7	11.32
Florida	218.0	10.75
Kentucky	43.2	9.77
Wyoming	5.1	8.76
Montana	9.0	8.75
South Carolina	36.5	7.45
Tennessee	48.0	7.27
Nebraska	12.9	6.80
West Virginia	12.4	6.72
Texas	181.7	6.62
South Dakota	5.3	6.17
Mississippi	17.2	5.75
Delaware	4.0	4.23
Georgia	41.5	4.06
Louisiana	13.4	2.87
Alabama	12.2	2.51
North Dakota	0.3	0.40
Virginia	0.1	0.01
Alaska	0.0	0.00
Guam	0.0	0.00
Kansas	0.0	0.00
Puerto Rico	0.0	0.00
Virgin Islands	0.0	0.00
US total	6,296.4	
Median	51.2	15.88

Appendix C. Summary of Large Customer Self-Direct Programs by State

State	Availability	Description
Arizona	Customers of Arizona Public Service Company (APS), Tucson Electric Power Company (TEP), and Salt River Project (SRP)	APS: Large customers using at least 40 million kWh per calendar year can elect to self direct energy efficiency funds. Customers must notify APS each year if they wish to participate, after which 85% of the customer's demand-side management contribution will be reserved for future energy efficiency projects. Projects must be completed within two years. Self-direct funds are paid once per year once the project is completed and verified by APS. TEP: To be eligible for self direct, a customer must use a minimum of 35 million kWh per calendar year. SRP: SRP makes self direct available only to very large customers using more than 240 million kWh per year. For all utilities, a portion of the funds they would have otherwise contributed to energy efficiency is retained to cover the self-direct program administration, management, and evaluation costs.
Colorado	Customers of Xcel Energy and Black Hills	Xcel: The self-direct program is available to commercial and industrial (C&I) electric customers who have an aggregated peak load of at least 2 MW in any single month and an aggregated annual energy consumption of at least 10 GWh. Self-direct program customers cannot participate in other conservation products offered by the company. Rebates are paid based on actual savings from a project, up to $525 per customer kW or $0.10 per kWh; rebates are given for either peak demand or energy savings but not both and are limited to 50% of the incremental cost of the project. Xcel uses raw monitoring results and engineering calculations to demonstrate actual energy and demand savings. Black Hills: To participate in the C&I self-direct program, customers must have an aggregated peak load greater than 1 MW in any single month and aggregated annual energy usage of 5,000 MWh. Rebates and savings are calculated on a case-by-case basis; rebate values are calculated as either 50% of the incremental cost of the project or $0.30 per kWh savings, whichever is lower.
Idaho	Customers of Idaho Power	Idaho Power offers its largest customers an option to self direct the 4% energy efficiency rider that appears on all customers' bills. Customers have three years to complete projects, with 100% of the funds available to fund up to 100% of project costs. Self-direct projects are subject to the same criteria as projects in other efficiency programs.
Illinois	Statewide for natural gas customers based on NAICS code; pilot program for ComEd electric customers	Self direct is generally applicable to customers of natural gas utilities subject to the Illinois Energy Efficiency Portfolio Standard. The North American Industry Classification System's Threshold code number is 22111 or any such code number beginning with the digits 31, 32, or 33 and annual usage in the aggregate of 4 million therms or more in the affected gas utility's service territory or with aggregate usage of 8 million therms or more in the state. Customers must agree to set aside for their own use in implementing energy efficiency 2% of the customer's cost of natural gas, composed of the customer's commodity cost and the delivery service charges paid to the gas utility, or $150,000, whichever is less. For evaluation, the Illinois Department of Commerce and Economic Opportunity has the ability to audit compliance and take remedial action for noncompliance.
Massachusetts	Statewide	The top five energy users in each utility were able to opt in to the self-direction option. However the pilot program ended in December 2015.

State	Availability	Description
Michigan	Statewide	Self-direct is available statewide. Customers must have had an annual peak demand in the preceding year of at least 1 MW in the aggregate at all sites. Customers may use the funds that would otherwise have been paid to the utility provider for energy efficiency programs. However they must submit the portion of the energy efficiency funds that would have been collected and used for low-income programs to their utility provider. They will then calculate the energy savings achieved and provide it to their utility provider. The percentage of eligible customers statewide is not calculated, but in 2009 there were 77 large customers who self directed; by 2014 that number had dropped to 24.
Minnesota	Statewide	Minnesota offers a self-direct option, with a full exemption from assigned cost-recovery mechanism fees, to customers with 20 MW average electric demand or 500,000 MCF of gas consumption. Customers must also show that they are making “reasonable” efforts to identify or implement energy efficiency and that they are subject to competitive pressures that make it helpful for them to be exempted from the CRM fees. Participating customers must submit new reports every five years to maintain exempt status. The utility is not involved in self-direct program administration; the state Department of Commerce manages self-direct accounts and is the arbiter of whether a company qualifies for self direct and is satisfying its obligations.
Montana	Statewide (all regulated public utilities)	Customers with average monthly demand of 1,000 kW can self direct universal systems benefits (USB) funds. Self-direct customers are reimbursed for their annual energy efficiency expenditures up to the amount of their annual total of USB rate payments to their utility. The transaction occurs directly between the customer and the utility, and the latter tabulates and summarizes self-directed funds annually. This does not include specifics or evaluation of efficiency projects. Evaluation of savings claims is not required.
New Mexico	Statewide in the territories of three investor-owned utilities (IOUs)	Self direct is available statewide. Customers who use more than 7,000 MWh annually may administer their own energy efficiency projects (Southwestern Public Service). They receive an exemption of, or a credit for, an amount equal to expenditures that they have made at their facilities on and after January 1, 2005. Evaluation is required. Public Service Company of New Mexico reported three self-direct programs in 2015. SPS reports no participants in either 2014 or 2015 and does not foresee any 2016 participants. El Paso Electric reported no participants in 2014.
Oregon	Customers of Portland General Electric, PacifiCorp, Idaho Power, and Emerald People’s Utility District (PUD)	The self-direct option for the Public Purpose Charge is required for two of the three investor-owned utilities. This program is uniform statewide across all impacted utilities. One consumer-owned utility has chosen to design and run a self-direct program. Programs cover approximately 80% of the electric customers in Oregon. Eligible sites must demonstrate that they were over 1 MW average in the prior year to enter and remain in the program. Participants in the three participating programs have the proposed projects technically reviewed by the Oregon Department of Energy. In two programs, expenditures toward qualified projects are used as credit to offset future Public Purpose Charges. The credit is applied on-bill. In the third program, the utility has a set-aside program in combination with credit toward future Public Purpose Charges. These funds are provided by check and/or on-bill. The Oregon Department of Energy conducts a technical review of claimed savings prior to project construction. They review a sampling of projects for actual performance. Of the estimated 230 eligible sites, 17 are participating. Utilities do not publish the percentage of eligible load saved. Total savings for 2015 was 2,743,000 kWh.

State	Availability	Description
Utah	Customers of Rocky Mountain Power	Rocky Mountain Power's self-direct program is a project-based rate credit program offering commercial/industrial customers up to 80% of eligible project costs back as a rate credit against the current DSM (Schedule 193) surcharge rate. Customers earn a credit of up to 100% of their CRM charge, but must pay a flat $500 administrative fee for each self-direct project. Under the Questar Gas ThermWise Business Custom Rebates program, self-direct rebates are available for the installation of energy efficiency measures. Incentives are the lesser of (a) a $10/decatherm for first-year annual decatherm savings as determined solely by the company, or (b) 50% of the eligible project cost as determined by the company. Customers can choose to engage in self direct and more traditional CRM programs simultaneously, provided the programs are used for different projects.
Vermont	Statewide for both electric and natural gas customers	For electric energy efficiency, three self-direct options are available statewide: the Self-Managed Energy Efficiency Program (SMEEP), the Customer Credit Program (CCP), and Energy Savings Accounts (ESA). SMEEP is also available for the state's one eligible gas customer. The SMEEP option requires prospective participants or their predecessors to have contributed $1.5 million to the Vermont Energy Efficiency Utility Fund (VEEUF) in 2008 through the Energy Efficiency Charge (EEC) adder on their electric costs. Only one customer meets that standard. Eligible customers must commit to investing a minimum of $3 million over a three-year program cycle. The ESA option allows Vermont businesses that pay an EEC in excess of $5,000 per year (or an average of $5,000 per year over three years) to use a portion of their EEC to support energy efficiency projects in their facilities. For CCP, eligible customers must be ISO 14001 certified and meet several conditions similar to ENERGY STAR for industrial facilities. Natural gas energy efficiency is available only for transmission and industrial electric and natural gas ratepayers who have a minimum of $1.5 million in customer efficiency charges for electric use. SMEEP allows an eligible customer to be exempt from the (electric) EEC if that customer commits to spending an annual average of no less than $1 million across three years on energy efficiency investments. In addition, the Vermont Public Service Board lets eligible Vermont business customers self-administer energy efficiency through an Energy Savings Account (ESA) or the CCP. These funds are still paid into the VEEUF and are disbursed to participants upon completion of an eligible energy efficiency measure. For natural gas, ESA and CCP participants can access a percentage of the funds paid into the VEEUF to undertake approved energy efficiency measures. For the SMEEP electric program, eligible customers must demonstrate that they have a comprehensive energy management program with annual objectives, or that they have achieved ISO 14001 certification. These customers must report to the Public Service Board, detailing the measures undertaken, the estimated energy and cost savings, and any related costs. These reports are then reviewed and approved by the Board. The ESA account operates through Efficiency Vermont; the related savings are reported and verified through the savings verification mechanism. For CCP, eligible customers must be ISO 14001 certified and meet several conditions similar to ENERGY STAR for industrial facilities. Savings are then verified through existing mechanisms.

State	Availability	Description
Washington	All utilities have the option to develop self-direct options for industrial and commercial customers, but of the IOUs, only Puget Sound Energy has developed a self-direct program	Puget Sound Energy's self-direct program is available only to industrial or commercial customers on electric rate-specific rate schedules. The self-direct program operates on a four-year cycle comprising two phases: noncompetitive and competitive. During the noncompetitive phase, customers have exclusive access to their energy efficiency funds, which are collected over the four-year period. When this phase closes, any unused funds are pooled together and competitively bid on by the members of the self-direct program. Customers receive payment in the form of a check once the project is complete and verified. Participating customers do not receive any rate relief when they complete energy efficiency investments. The utility pre- and post-verifies 100% of the projects, including a review and revision of savings calculations to determine incentive levels. The program is included in the third-party evaluation cycle like any other utility conservation programs.
Wisconsin	Statewide	A self-direct option is open to customers that meet the definition of a large energy customer according to the 2005 Wisconsin Act 141. Under the self-direct option, a true-up at the end of the year returns contributions to participating customers for use on energy efficiency projects. Evaluation is required under Public Service Commission Administrative Code 137, with evaluation plans reviewed by that commission. This option has been available since 2008, but no customers have participated to date.
Wyoming	Customers of Rocky Mountain Power	Rocky Mountain Power offers a self-direct option for customers. The self-direct program is a project-based rate credit program that offers up to 80% of eligible project costs back to customers as a rate credit against the 3.7% CRM charge that all customers pay. Customers earn a credit of up to 100% of their CRM charge, but must pay a flat $500 administrative fee for each self-direct project. Customers can choose to engage in self-direct and more traditional CRM programs simultaneously, provided the different programs are used to deploy different projects.

Appendix D. Details of States' Energy Efficiency Resource Standards

State Year(s) enacted Authority Applicability (% sales affected)	Description	Avg. incremental electric savings target per year (2015 onward)	Stringency	Reference	Score
Arizona 2010 Regulatory Electric and nat. gas IOUs, co-ops (~59%)	Electric: Incremental savings targets began at 1.25% of sales in 2011, ramping up to 2.5% in 2016–2020 for cumulative annual electricity savings of 22% of retail sales, of which 2% may come from peak demand reductions. Natural gas: ~0.6% annual savings (for cumulative savings of 6% by 2020). Co-ops must meet 75% of targets.	2.5%	Binding	Docket No. RE-00000C-09-0427, Decision 71436 Docket No. RE-00000C-09-0427, Decision 71819 Docket No. RG-00000B-09-0428 Decision 71855	3
Arkansas 2010 Regulatory Electric and nat. gas IOUs (~53%)	Electric: Incremental targets for PY 2017 and PY 2018 of 0.90% of 2015 retail sales for electric IOUs, increasing to 1.00% for PY 2019. Natural gas: Annual incremental reduction target of 0.50% for 2017–2019 for natural gas IOUs.	0.9%	Opt out	Order No. 17, Docket No. 08-144-U; Order No. 1, Docket No. 13-002-U Order No. 7, Docket No. 13-002-U Order No. 31, Docket No. 13-002-U	1
California 2004, 2009, and 2015 Legislative Electric and nat. gas IOUs (~78%)	Electric: Average incremental savings targets of ~1.15% of retail sales electricity. In October 2015, California enacted SB 350, calling on state agencies and utilities to work together to double cumulative efficiency savings by 2030. Natural gas: Incremental savings target of 0.56% for natural gas. Utilities must pursue all cost-effective efficiency resources.	1.2%	Binding	CPUC Decision 04-09-060; CPUC Decision 08-07-047; CPUC Decision 14-10-046 AB 995 SB 350 (10/7/15) AB 802 (10/8/15)	1.5

State Year(s) enacted Authority Applicability (% sales affected)	Description	Avg. incremental electric savings target per year (2015 onward)	Stringency	Reference	Score
Colorado 2007 and 2013 Legislative Electric and nat. gas IOUs (~57%)	Electric: Black Hills follows Public Service Company of Colorado (PSCo) incremental savings targets of 0.8% of sales in 2011, increasing to 1.35% of sales in 2015. For the period 2015–2020, PSCo must achieve incremental savings of at least 400 GWh per year. Natural gas: Savings targets commensurate with spending targets (at least 0.5% of prior year's revenue).	1.3%	Binding	Colorado Revised Statutes 40-3.2-101, et seq.; Docket No. 12A-100E Dec. R12-0900; Docket No. 10A-554EG Docket No. 13A-0686EG Dec. C14-0731	1.5
Connecticut 2007 and 2013 Legislative Electric and nat. gas IOUs (~94%)	Electric: Average incremental savings of 1.51% of sales from 2016–2018. Natural gas: Average incremental savings of 0.61% per year from 2016–2018. Utilities must pursue all cost-effective efficiency resources.	1.5%	Binding	Public Act No. 07-242 Public Act No. 13-298 2016-2018 Electric and Natural Gas Conservation and Load Management Plan	2
Hawaii 2004 and 2009 Legislative Electric Statewide goal (100%)	In 2009, transitioned away from a combined RPS-EERS to a standalone EEPS goal to reduce electricity consumption by 4,300 GWh by 2030 (equal to ~30% of forecast electricity sales, or 1.4% annual savings).	1.4%	Binding	HRS §269-91, 92, 96 HI PUC Order, Docket No. 2010-0037	1.5
Illinois 2007 Legislative Electric and nat. gas Utilities with more than 100,000 customers, Illinois DCEO (~88%)	Electric: Legislative targets of 0.2% incremental savings in 2008, ramping up to 2.0% in 2015 and thereafter. Annual peak demand reduction of 0.1% through 2018. Energy efficiency spending may not exceed an established cost cap. As a result, regulators have approved lower targets in recent years, with incremental electric savings targets varying by utility from 0.6–0.7% per year. Natural gas: 8.5% cumulative savings by 2020 (0.2% incremental savings in 2011, ramping up to 1.5% in 2019).	0.7%	Cost cap	SB 1918 Public Act 96-0033 § 220 ILCS 5/8-103 Case No. 13-0495 Case No. 13-0498	1

State Year(s) enacted Authority Applicability (% sales affected)	Description	Avg. incremental electric savings target per year (2015 onward)	Stringency	Reference	Score
Iowa 2009 Legislative Electric and nat. gas IOUs (75%)	Electric: Incremental savings targets vary by utility from ~1.1–1.2% annually through 2018. Natural gas: Incremental savings targets vary by utility, ~0.66–1.2% annually through 2018.	1.2%	Binding	SB 2386 Iowa Code § 476 Docket No. EEP-2012-0001	1.5
Maine 2009 Legislative Electric and nat. gas Efficiency Maine (100%)	Electric: Savings of 20% by 2020, with incremental savings targets of ~ 1.6% per year for 2014–2016 and ~2.4% per year for 2017–2019. Natural gas: Incremental savings of ~0.2% per year for 2017–2019. Efficiency Maine operates under an all cost-effective mandate.	2.4%	Opt out	Efficiency Maine Triennial Plan (2014-2016) Efficiency Maine Triennial Plan (2017-2019) HP 1128 – LD 1559	3
Maryland 2008 and 2015 Legislative through 2015, regulatory thereafter Electric IOUs (99%)	15% per-capita electricity use reduction goal by 2015 (10% by utilities, 5% achieved independently). 15% reduction in per capita peak demand by 2015 compared to 2007. After 2015, targets vary by utility, ramping up by 0.2% per year to reach 2% incremental savings.	2.0%	Binding	Md. Public Utility Companies Code § 7-211 MD PSC Docket Nos. 9153–9157 Order No. 87082	2.5
Massachusetts 2009 Legislative Electric and nat. gas IOUs, co-ops, muni's, Cape Light Compact (~86%)	Electric: Average incremental savings of 2.93% of electric sales for 2016–2018. Natural gas: Average incremental savings of 1.24% per year for 2016–2018. All cost-effective efficiency requirement.	2.9%	Binding	DPU 15-160 through DPU 15-169 (MA Joint Statewide Three-Year Electric and Gas Energy Efficiency Plan 2016-2018) MGL ch. 25, § 21;	3
Michigan 2008 Legislative Electric and nat. gas Statewide goal (100%)	Electric: 0.3% incremental savings in 2009, ramping up to 1% in 2012 and each year thereafter. Natural gas: 0.10% annual savings in 2009, ramping up to 0.75% in 2012 and each year thereafter.	1.0%	Cost cap	MGL ch. 25, § 21; Act 295 of 2008	1.5

State Year(s) enacted Authority Applicability (% sales affected)	Description	Avg. incremental electric savings target per year (2015 onward)	Stringency	Reference	Score
Minnesota 2007 Legislative Electric and nat. gas Statewide goal (100%)	Electric: 1.5% incremental savings in 2010 and each year thereafter. Natural gas: 0.75% incremental savings per year in 2010–2012; 1% incremental savings in 2013 and each year thereafter.	1.5%	Binding	Minn. Stat. § 216B.241	2
Nevada 2005 and 2009 Legislative Electric IOUs (~62%)	20% of retail electricity sales to be met by renewables and energy efficiency by 2015, and 25% by 2025. Energy efficiency may meet a quarter of the standard through 2014, but allowances phase out by 2025.	0.4%	Binding	NRS 704.7801 et seq.	0
New Hampshire 2016 Regulatory Electric and nat. gas Statewide goal (100%)	Electric: 0.8% incremental savings in 2018, ramping up to 1.0% in 2019 and 1.3% in 2020. Natural gas: 0.7% in 2018, 0.75% in 2019, and 0.8% in 2020.	1.0%	Binding	NH PUC Order No. 25932, Docket DE 15-137	1.5
New Mexico 2008 and 2013 Legislative Electric IOUs (68%)	5% reduction from 2005 total retail electricity sales by 2014, and 8% reduction by 2020.	0.6%	Binding	NM Stat. § 62-17-1 et seq.	0.5

State Year(s) enacted Authority Applicability (% sales affected)	Description	Avg. incremental electric savings target per year (2015 onward)	Stringency	Reference	Score
New York 2008 and 2016 Regulatory Electric and nat. gas Statewide goal (100%)	Electric: Under current Reforming the Energy Vision (REV) proceedings, utilities have filed efficiency transition implementation plans (ETIPS) with incremental targets varying from 0.4% to 0.9% for the period 2016–2018. In January, the PSC authorized NYSERDA's Clean Energy Fund (CEF) framework, which outlines a minimum 10-year energy efficiency goal of 10.6 million MWh measured in cumulative first year savings. The PSC issued a REV II Track Order in May prescribing that the Clean Energy Advisory Council also propose utility targets supplemental to ETIPS by October 2016. Some degree of overlap of program savings is anticipated between utility targets and NYSERDA CEF goals. Natural gas: Utilities have filed proposals for varying incremental targets averaging incremental savings of 0.28% for the period 2016–2018.	0.7%	Binding	NY PSC Order, Case 07-M-0548 NY PSC Case 14-M-0101 NY PSC Case 14-M-0252 2015 New York State Energy Plan NY PSC Order authorizing the Clean Energy Fund framework	1
North Carolina 2007 Legislative Electric Statewide goal (100%)	Renewable Energy and Energy Efficiency Portfolio Standard (REPS) requires renewable generation and/or energy savings of 6% by 2015, 10% by 2018, and 12.5% by 2021 and thereafter. Energy efficiency is capped at 25% of target, increasing to 40% in 2021 and thereafter.	0.4%	Opt out	NC Gen. Stat. § 62-133.8 04 NCAC 11 R08-64, et seq.	0
Ohio 2008 and 2014 Legislative Electric IOUs (~89%)	Beginning in 2009, incremental savings of 0.3% per year, ramping up to 1% in 2014. A “freeze” in 2015 and 2016 allows utilities that have achieved 4.2% cumulative savings to reduce or eliminate program offerings. With no additional legislative action, savings targets will resume under the original policy in 2017.	0.6%	Binding	ORC 4928.66 et seq. SB 221 SB 310	0.5

State Year(s) enacted Authority Applicability (% sales affected)	Description	Avg. incremental electric savings target per year (2015 onward)	Stringency	Reference	Score
Oregon 2010 Regulatory Electric and nat. gas Energy Trust of Oregon (~70%)	Electric: Incremental targets average ~1.3% of sales annually for the period 2015–2019. Natural gas: 0.3% of sales annually for the period 2015–2019	1.3%	Binding	Energy Trust of Oregon 2015-2019 Strategic Plan Grant Agreement between Energy Trust of Oregon and OR PUC	1.5
Pennsylvania 2004 and 2008 Legislative Electric Utilities with more than 100,000 customers (~93%)	Varying targets have been set for IOUs amounting to yearly statewide incremental savings of 0.8% savings for 2016–2020. EERS includes peak demand targets. Energy efficiency measures may not exceed an established cost cap.	0.8%	Cost cap	66 Pa C.S. § 2806.1 PUC Order Docket No. M-2008-2069887 PUC Implementation Order Docket M-2012-2289411 PUC Final Implementation Order Docket M-2014-2424864	0.5
Rhode Island 2006 Legislative Electric and nat. gas IOUs, muni's (~99%)	Electric: Incremental savings of 2.5% in 2015, 2.55% in 2016, and 2.6% in 2017. EERS MW targets. Natural gas: Incremental savings of 1% in 2015, 1.05% in 2016, and 1.1% in 2017. Utilities must acquire all cost-effective energy efficiency.	2.6%	Binding	RIGL § 39-1-27.7 Docket No. 4443	3
Texas 1999 and 2007 Legislative Electric IOUs (~73%)	20% incremental load growth in 2011 (equivalent to ~0.10% annual savings); 25% in 2012, and 30% in 2013 and onward. Peak demand reduction targets of 0.4% compared to previous year. Energy efficiency measures may not exceed an established cost cap.	0.1%	Cost cap, opt out	SB 7; HB 3693; Substantive Rule § 25.181 SB 1125	0

State Year(s) enacted Authority Applicability (% sales affected)	Description	Avg. incremental electric savings target per year (2015 onward)	Stringency	Reference	Score
Vermont 2000 Legislative Electric Efficiency Vermont, Burlington Electric (100%)	Average incremental electricity savings of ~2.1% per year from 2015–2017. EERS includes demand response targets. Energy efficiency utilities must set budgets at a level that would realize all cost-effective energy efficiency.	2.1%	Binding	30 VSA § 209 VT PSB Docket EEU-2010-06 Efficiency Vermont Triennial Plan 2015–17 (2016 Update)	3
Washington 2006 Legislative Electric IOUs, co-ops, muni's (~81%)	Biennial and 10-year goals vary by utility. Law requires savings targets to be based on the Northwest Power Plan, which estimates potential incremental savings of ~1.5% per year through 2030 for Washington utilities. All cost-effective conservation requirement.	1.5%	Binding	Ballot Initiative I-937 Energy Independence Act, ch. 19.285.040 WAC 480-109-100 WAC 194-37 Seventh Northwest Power Plan (adopted 2/10/16)	1.5
Wisconsin 2011 Legislative Electric and nat. gas Statewide goal (100%)	Electric: Focus on Energy targets include incremental electricity savings of ~0.81% of sales per year in 2015–2018. Natural gas: Incremental savings of 0.6% in 2015–2018. Energy efficiency measures may not exceed an established cost cap.	0.8%	Cost cap	Order, Docket No. 5-FE-100: Focus on Energy Revised Goals and Renewable Loan Fund (10/15) Program Administrator Contract, Docket No. 9501-FE-120, Amendment 2 (3/16) 2005 Wisconsin Act 141	1

Appendix E. Tax Incentives for High-Efficiency Vehicles

State	Tax incentive
Arizona	EV owners in Arizona pay a significantly reduced vehicle license tax—$4 for every $100 in assessed value—as part of the state's Reduced Alternative Fuel Vehicle License Tax program.
California	AB 118 targets medium- and heavy-duty trucks in a voucher program whose goal is to reduce the up-front incremental cost of purchasing a hybrid vehicle. Vouchers range from $12,000 to $110,000, depending on vehicle specifications, and are paid directly to fleets that purchase hybrid trucks for use within the state. California also offers tax rebates of up to $5,000 for light-duty zero-emission EVs and plug-in hybrid EVs on a first-come, first-served basis, effective until 2023.
Colorado	On May 4, the Colorado legislature approved HB 1332, a bill that dramatically improves the state's alternative fuel vehicle tax credits. It sets a flat $5,000 credit for the purchase of a light-duty electric vehicle and makes the credits assignable to a car dealer or finance company effectively turning the credit into a point of sale incentive.
Connecticut	Connecticut's Hydrogen and Electric Automobile Purchase Rebate Program provides as much as $3,000 for the incremental cost of the purchase of a hydrogen fuel cell electric vehicle (FCEV), all-electric vehicle, or plug-in hybrid electric vehicle. Rebates are calculated on the basis of battery capacity. Vehicles with a battery capacity of 18 kWh or more earn $3,000, while those with capacities between 7 kWh and 18kWh earn $1,500. Vehicles with batteries smaller than 7 kWh are eligible for a rebate of $750.
Delaware	As part of the Delaware Clean Transportation Incentive Program, plug-in electric vehicles earn a rebate of $2,200.
District of Columbia	The District of Columbia offers a reduced registration fee and a vehicle excise tax exemption for owners of all vehicles with an EPA estimated city fuel economy of at least 40 miles per gallon.
Georgia	An income tax credit is available to individuals who purchase new commercial medium- or heavy-duty vehicles that run on alternative fuels including electricity. Medium-duty vehicles qualify for a credit up to $12,000, while heavy-duty vehicles can earn a credit of up to $20,000.
Guam	A rebate of up to 10% the base price of a plug-in vehicle is available to residents and businesses.
Louisiana	Louisiana offers an income tax credit equivalent to 50% of the incremental cost of purchasing an EV under the state's alternative-fuel vehicle tax credit program. Alternatively, taxpayers may claim the lesser of 10% of the total cost of the vehicle or $3,000.
Maryland	Purchasers of qualifying all-electric and plug-in hybrid-electric light-duty vehicles may claim up to $3,000 against the vehicle excise tax in Maryland, depending on the vehicle's battery weight.
Massachusetts	The Massachusetts Offers Rebates for EVs (MOR-EV) program offers rebates of up to $2,500 to customers purchasing plug-in EVs.
New Jersey	All ZEVs in New Jersey are exempt from state sales and use taxes.
New York	New York started the New York Truck Voucher Incentive Program in 2014. Vouchers of up to $60,000 are available for the purchase of hybrid and all-electric class 3–8 trucks.
Puerto Rico	In 2012, Puerto Rico amended the Internal Revenue Code to allow an excise tax reimbursement of up to 65% for buyers of hybrid and plug-in hybrid vehicles. The reimbursement ranges from $2,000 to $8,000 and is available through 2016. Buyers of all-electric vehicles are waived from paying excise tax altogether.

State	Tax incentive
Rhode Island	Rhode Island offers buyers of plug-in electric vehicles rebates of up to $2,500 depending on battery capacity. Vehicles with battery capacity of 18 kilowatt-hours (kWh) or above earn $2,500, vehicles with battery capacity between 7 and 18 kWh earn $1,500, and those with capacity less than 7 kWh qualify for a $500 rebate.
South Carolina	South Carolina offers up to $2,000 in tax credits for the purchase of a plug-in hybrid EV. The credit is equal to $667, plus $111 if the vehicle has at least 5 kWh of battery capacity, and an additional $111 for each additional kWh above 5 kWh.
Tennessee	Plug-in electric vehicles bought after June 2015 qualify for a rebate from the Tennessee Department of Environment and Conservation (TDEC). Dealerships will distribute rebates of $2,500 for all-electric vehicles and rebates of $1,500 for plug-in hybrid vehicles.
Texas	EVs weighing 8,500 pounds or less and purchased after September 1, 2013 are eligible for a $2,500 rebate.
Utah	Through 2016, all-electric vehicles are eligible for an income tax credit of 35% of the vehicle purchase price, up to $1,500. Plug-in hybrids qualify for a tax credit of $1,000.
Washington	EVs are exempt from state motor vehicle sales and use taxes under the Alternative Fuel Vehicle Tax Exemption Program.

Source: DOE 2016

Appendix F. State Transit Funding

State	FY 2013 funding ($million)	2013 population*	Per capita transit expenditure
Maryland	1,522.1	5,928,814	$256.73
Alaska	181.6	735,132	$246.98
New York	4,465.9	19,651,127	$227.26
Massachusetts	1,392.9	6,692,824	$208.11
Connecticut	474.3	3,596,080	$131.90
New Jersey	1,076.5	8,899,339	$120.96
Delaware	95.3	925,749	$102.91
District of Columbia	454.8	5,000,000	$90.96
Pennsylvania	1,161.1	12,773,801	$90.90
California	3,040.7	38,332,521	$79.32
Illinois	854.7	12,882,135	$66.35
Minnesota	307.7	5,420,380	$56.76
Rhode Island	51.6	1,051,511	$49.10
Virginia	262.3	8,260,405	$31.75
Michigan	271.8	9,895,622	$27.47
Wisconsin	106.5	5,742,713	$18.54
Vermont	7.5	626,630	$11.94
Oregon	40.4	3,930,065	$10.28
Florida	189.3	19,552,860	$9.68
Indiana	57.9	6,570,902	$8.81
North Carolina	84.6	9,848,060	$8.59
Washington	59.9	6,971,406	$8.59
North Dakota	5.3	723,393	$7.32
Tennessee	40.1	6,495,978	$6.17
Wyoming	2.7	582,658	$4.63
Iowa	12.9	3,090,416	$4.17

State	FY 2013 funding ($million)	2013 population	Per capita transit expenditure
New Mexico	7.6	2,085,287	$3.65
Colorado	14.0	5,268,367	$2.66
Kansas	6.0	2,893,957	$2.07
Nebraska	2.9	1,868,516	$1.55
West Virginia	2.8	1,854,304	$1.50
Oklahoma	5.8	3,850,568	$1.49
South Carolina	6.0	4,774,839	$1.26
Texas	31.9	26,448,193	$1.21
Arkansas	3.5	2,959,373	$1.18
Louisiana	5.0	4,625,470	$1.07
South Dakota	0.8	844,877	$0.91
Ohio	7.3	11,570,808	$0.63
Montana	0.5	1,015,165	$0.54
Mississippi	1.6	2,991,207	$0.53
Maine	0.5	1,328,302	$0.41
Kentucky	1.7	4,395,295	$0.40
Georgia	2.9	9,992,167	$0.30
Idaho	0.3	1,612,136	$0.19
Missouri	0.6	6,044,171	$0.09
New Hampshire	0.1	1,323,459	$0.04
Nevada	0	2,790,136	$0.01
Alabama	0	4,833,722	$0.00
Arizona	0	6,626,624	$0.00
Hawaii	0	1,404,054	$0.00
Utah	0	2,900,872	$0.00

* Population figures represent total area served by transit system. *Source:* AASHTO 2015.

Appendix G. State Transit Legislation

State	Description of transit legislation	Source
Arkansas	Passed in 2001, Arkansas Act 949 established the Arkansas Public Transit Fund, which directs monies from rental vehicle taxes toward public transit expenditures.	ftp://www.arkleg.state.ar.us/acts/2001/htm/ACT949.pdf
California	California's Transportation Development Act provides two sources of funding for public transit: the Location Transportation Fund (LTF) and the State Transit Assistance (STA) Fund. The general sales tax collected in each county is used to fund each county's LTF. STA funds are appropriated by the legislature to the state controller's office. The statute requires that 50% of STA funds be allocated according to population and 50% be allocated according to operator revenues from the prior fiscal year.	www.dot.ca.gov/hq/MassTrans/State-TDA.html
Colorado	Colorado adopted the FASTER legislation in 2009, creating a State Transit and Rail Fund that accumulates $5 million annually. The legislation also allocated $10 million per year from the Highway Users Tax Fund to the maintenance and creation of transit facilities. Colorado subsequently passed SB 48 in 2013, which allowed for the entire local share of the Highway Users Trust Fund (derived from state gas tax and registration fees) to be used for public transit and bicycle or pedestrian investments.	www.leg.state.co.us/clics/clics2009a/csl.nsf/billcontainers/636E40D6A83E4DE987257537001F8AD6/$FILE/108_enr.pdf www.leg.state.co.us/CLICS/CLICS2013A/csl.nsf/fsbillcont3/9D4690717C1FF9DC87257AEE00572392?Open&file=048_enr.pdf
Florida	House Bill 1271 allows municipalities in Florida with a regional transportation system to levy a tax, subject to voter approval, that can be used as a funding stream for transit development and maintenance.	www.myfloridahouse.gov/sections/Bills/billsdetail.aspx?BillId=44036
Georgia	The Transportation Investment Act, enacted in 2010, allows municipalities to pass a sales tax for the express purpose of financing transit development and expansion.	gsfic.georgia.gov/transportation-investment-act
Hawaii	Section HRS 46-16.8 of the Hawaii Revised Statutes allows municipalities to add a county surcharge on state tax that is then funneled toward mass transit projects.	www.capitol.hawaii.gov/hrscurrent/Vol02_Ch0046-0115/HRS0046/HRS_0046-0016_0008.htm
Illinois	House Bill 289 allocates $2.5 billion for the creation and maintenance of mass transit facilities from the issuance of state bonds.	legiscan.com/gaits/text/70761
Indiana	House Bill 1011 specifies that a county or city council may elect to provide revenue to a public transportation corporation from the distributive share of county adjusted gross income taxes, county option income taxes, or county economic development income taxes. An additional county economic development income tax no higher than 0.3% may also be imposed to pay the county's contribution to the funding of the metropolitan transit district. Only six counties within the state may take advantage of this legislation.	legiscan.com/IN/text/HB1011/id/673339

State	Description of transit legislation	Source
Iowa	The Iowa State Transit Assistance Program devotes 4% of the fees for new registration collected on sales of motor vehicle and accessory equipment to support public transportation.	www.iowadot.gov/transit/funding.html
Kansas	The Transportation Works for Kansas legislation was adopted in 2010 and provides financing for a multimodal development program in communities with immediate transportation needs.	votesmart.org/bill/11412/30514/transportation-works-for-kansas-program%20%28T-Works%20for%20Kansas%20Program%29
Maine	The Maine Legislature created a dedicated revenue stream for multimodal transportation in 2012. Through sales tax revenues derived from taxes on vehicle rentals, Maine's Multimodal Transportation Fund must be used for the purposes of purchasing, operating, maintaining, improving, repairing, constructing, and managing the assets of nonroad forms of transportation.	www.mainelegislature.org/legis/statutes/23/title23sec4210-B.html
Massachusetts	Section 35T of Massachusetts general law establishes the Massachusetts Bay Transportation Authority State and Local Contribution Fund. This account is funded by revenues from a 1% sales tax.	malegislature.gov/Laws/GeneralLaws/PartI/TitleII/Chapter10/Section35t
Michigan	The Michigan Comprehensive Transportation Fund funnels both vehicle registration revenues and auto-related sales tax revenues toward public transportation and targeted transit demand management programs.	www.legislature.mi.gov/(S(hlkm5k45i240utf2mb0odtzt))/mileg.aspx?page=getObject&objectName=mcl-247-660b
Minnesota	House File 2700, adopted in 2010, is an omnibus bonding and capital improvement bill that provides $43.5 million for transit maintenance and construction. The bill also prioritized bonding authorization so that appropriations for transit construction for fiscal years 2011 and 2012 would amount to $200 million.	wdoc.house.leg.state.mn.us/leg/LS86/CEH2700.1.pdf
New York	In 2010, New York adopted Assembly Bill 8180, which increased certain registration and renewal fees to fund public transit. It also created the Metropolitan Transit Authority financial assistance fund to support subway, bus, and rail.	www.ncsl.org/issues-research/transport/major-state-transportation-legislation-2010.aspx#N
North Carolina	In 2009, North Carolina passed House Bill 148, which called for the establishment of a congestion relief and intermodal transportation fund.	www.ncleg.net/sessions/2009/bills/house/pdf/h148v2.pdf
Oregon	Oregon has a Lieu of State Payroll Tax Program that provides a direct ongoing revenue stream for transit districts that can demonstrate equal local matching revenues from state agency employers in their service areas.	www.oregonlegislature.gov/citizen_engagement/Reports/2008PublicTransit.pdf
Pennsylvania	Act 44 of House Bill 1590, passed in 2007, allows counties to impose a sales tax on liquor or an excise tax on rental vehicles to fund the development of their transit systems.	www.legis.state.pa.us/WU01/LI/LI/US/HTM/2007/0/0044..HTM

State	Description of transit legislation	Source
Tennessee	Senate Bill 1471, passed in 2009, calls for the creation of a regional transportation authority in major municipalities. It allows these authorities to set up dedicated funding streams for mass transit either by law or through voter referendum.	state.tn.us/sos/acts/106/pub/pc0362.pdf
Virginia	House Bill 2313, adopted in 2013, created the Commonwealth Mass Transit Fund, which will receive approximately 15% of revenues collected from the implementation of a 1.5% sales and use tax for transportation expenditures.	lis.virginia.gov/cgi-bin/legp604.exe?131+ful+CHAP0766
Washington	In 2012, Washington adopted House Bill 2660, which created an account to provide grants to public transit agencies to preserve transit service.	apps.leg.wa.gov/documents/billdocs/2011-12/Pdf/Bills/Session%20Laws/House/2660.SL.pdf
West Virginia	In 2013, the West Virginia Commuter Rail Access Act (Senate Bill 03) established a special fund in the state treasury to pay track access fees accrued by commuter rail services operating within West Virginia borders. The funds have the ability to rollover from year to year and are administered by the West Virginia State Rail Authority.	www.legis.state.wv.us/Bill_Status/bills_text.cfm?billdoc=SB103%20SUB1%20ENR.htm&yr=2013&sesstype=RS&i=103

Appendix H. State Progress toward Public Building Energy Benchmarking Requirements

State	Percentage benchmarked
California	100% of state-owned executive branch facilities have been benchmarked since 2013
Connecticut	42% of state buildings and 100% of the Connecticut Technical High School system
District of Columbia	Approximately 64% of public buildings
Michigan	17% of state-owned or leased buildings
Mississippi	95% of agencies covered by the energy and cost data reporting requirements under the Mississippi Energy Sustainability and Development Act of 2013
Missouri	50% of square footage managed by the Missouri Office of Administration and the Department of Corrections.
Montana	Approximately 15%
Nevada	Approximately 74% of state-owned building square-footage will have benchmarking programs in place in the coming months
New Mexico	Approximately 20%
Oregon	100% of state owned and occupied buildings greater than 5,000 square feet
Rhode Island	100% of all state, municipal, and public school square footage
Tennessee	23% of state-owned buildings
Utah	Approximately 80–90% of state-owned buildings are benchmarked to some degree
Vermont	70% of the state-owned and operated building space that the ENERGY STAR Portfolio Manager is capable of benchmarking
Washington	99% of buildings owned by state agencies, or 74% of buildings owned and leased by the state (including higher education facilities)

Not all states with benchmarking requirements provided the percentage of buildings benchmarked. All states listed above, except Missouri, require benchmarking in public facilities. Missouri has a voluntary benchmarking program.

Appendix I. State Energy Savings Performance Contracting: Energy Savings, Cost Savings, and Spending

State	2015 incremental electricity savings (kWh)	Total annual savings from active projects (kWh)	Spending ($)	Savings ($)
California	Approximately 25% of original facility energy use	Approximately 25% of original facility energy use		
Connecticut	Eversource Municipal Projects: 3,498,337 kWh (2015 Annual), 43,914,482 kWh (2015 Lifetime) Yankee Gas Municipal Projects: 52,311 therms (2015 Annual), 616,633 (2015 Lifetime)	Total Incremental Electricity Savings (2013–2015) for Eversource Municipal Projects: 8,184,822 kWh (Annual), 100,724,987 kWh (Lifetime) Total Incremental Electricity Savings (2013–2015) for Yankee Gas Municipal Projects: 202,527 therms (Annual), 2,394,683 therms (Lifetime)		$6 million projected annual energy cost avoidance for active state projects
Delaware		133,276,928 kBtus in 2015 for measures previously implemented in public buildings (includes both electricity and fuel savings)		
Kentucky			Nearly $800 million in ESPC since enabling legislation in 1996	

State	2015 incremental electricity savings (kWh)	Total annual savings from active projects (kWh)	Spending ($)	Savings ($)
Massachusetts			The state spent $40 million in 2015 on projects implemented under the Department of Capital and Asset Management and Maintenance (DCAMM) DOER Accelerated Energy Program. Under the DOE Better Buildings Performance Contracting Accelerator, DOER pledged at least $350 million to energy projects at state and municipal buildings between 2013 and 2016. Nearly 76% of this commitment has been met.	DCAMM DOER Accelerated Energy Program projects will save $2 million in annual energy costs over the next 20 years. The DOE's Better Buildings Performance Contracting Accelerator projects are estimated to save states more than $9 million and municipalities more than $5.8 million in annual energy costs.
Michigan	5,269,230 kWh			
Minnesota	1,608,021 kWh for all active ESCO projects in 2015 that the Minnesota Department of Commerce is aware of (including Riverland)	12,198,499 kWh for all active ESCO projects in 2015 or earlier that the Minnesota Department of Commerce is aware of (including one year of Riverland and two years of Bemidji)		
Mississippi	1,820,501 kWh			
Nevada	381,668 kWh	6,199,403 kWh		
New Mexico	Incremental savings for 2015 projects was 3.67 kWh. Gas savings in 2015 was 170,000 therms.	Annual savings are 16.1 million kWh per year. Gas savings are 528,000 therms per year. Carbon dioxide emissions reduced are 31.9 million lbs per year.	$49.5 million worth of projects in the last few years, with $15.7 million worth of efficiency projects under construction	
New York	In 2014, NYPA helped public entities implement projects with energy savings of approximately 66,000 MWh annually.	Since 2014, NYPA has helped public entities implement projects with energy savings of 1,330,000 MWh annually.	In 2014, NYPA initiated approximately $240 million in energy efficiency projects.	
North Carolina			In 2015, $274 million was invested in performance contracts with state agencies and universities.	These projects have achieved $47 million in utility savings to date.

State	2015 incremental electricity savings (kWh)	Total annual savings from active projects (kWh)	Spending ($)	Savings ($)
Pennsylvania	No new ESPC projects generating savings were completed in 2015.	200,000,000 kWh estimated total annual savings from active projects.		
Puerto Rico	Not available (no measures have been implemented in 2015)	From 2013 to June 2015, 3,337,710 kWh have been saved in one building alone, equivalent to more than 60% savings for the past 2 years.		
Rhode Island	About 8,256 MMBtus saved in 2015		The Rhode Island Public Energy Partnership has a $1 million budget.	About $257,621 annual savings for projects completed in 2015
Tennessee	The ESPC project in Memphis has seen a bill-to-bill energy reduction of 38% over the past year. The City of Knoxville did not implement any ESCO measures in 2015.	Knoxville's ESPC projects achieved 12,138,202 kWh in annual savings (electricity only) in 2015. The projects also achieved 8,692 MBtus in natural gas savings in 2015.	The Tennessee Board of Regents spent $54,000,000 on ESPC projects through FY 2014.	
Virginia	Net present value (NPV) of net savings in 2015 was $14,132,237. NPV is the value of avoided costs that exceed debt service during and after repayment of loan.			The NPV of net savings on all ESPC projects since 2001 is $177.74 million.
Washington	1,157,995 kWh annual guaranteed savings for projects completed in 2015	18,015,500 kWh annual guaranteed savings from projects completed from 2005 through 2015	Since the Performance Contracting Program was started in 1986, the state has invested more than $1 billion in public facility efficiency projects. The state has also received $442 million in utility rebates for those projects.	Saves $22 million in annual energy costs

We excluded ESPC program budgets as well as projected energy and cost savings from states in order to focus on investments and cost and energy savings already achieved.

Appendix J. Total Energy and Cost Savings from State Financial Incentives

State	Title	Program administrator	Total energy savings	Total cost savings ($)
Alabama	AlabamaSAVES Revolving Loan Program	Alabama State Energy Office, Abundant Power Solutions, LLC	87.3M kWh/yr	$7M/yr
Alabama	Local Government Energy Loan Program	Alabama State Energy Office, PowerSouth	2,100,703 kWh projected for loans approved in 2015	$593,071 annual savings projected for loans approved in 2015
Alaska	Weatherization Program	Alaska Housing Finance Corporation (AHFC)	60 MMBtus, annually on average per home	
California	Bright Schools Program	California Energy Commission	7,975,287 kWh	$1,413,632
California	California Clean Energy Jobs Act program (Prop 39 K-12 Program)	California Energy Commission	163,371,493 kWh	$32 million, including kWh, therm, propane, and fuel oil savings
California	Energy Partnership Program	California Energy Commission	836,713 kWh	$138,055
California	Energy Efficiency Financing for Public Sector Projects	California Energy Commission	11,305,945 kWh	$1,647,292
California	Energy Conservation Assistance Act—Education Subaccount (ECAA-Ed)	California Energy Commission	11,305,945 kWh	$1,647,292
Connecticut	Local Option—Commercial PACE Financing	Connecticut Green Bank (CGB)	33,558 MMBtus annually from projects in CY 2015	

State	Title	Program administrator	Total energy savings	Total cost savings ($)
Massachusetts	Green Communities Grant Program	Massachusetts Department of Energy Resources	Sum of Total Energy Savings: 77,772,567 kWh Sum of Total Lifetime Energy Savings: 941,400,059 kWh	$7,616,036 in annual cost savings
Minnesota	Fix-Up Loan	Minnesota Housing Finance Agency	2,693 kWh	$317
Minnesota	Energy Savings Partnership Program	Saint Paul Port Authority	526,000 kWh	$101,819
Mississippi	Energy Efficiency Revolving Loan Fund	Mississippi Development Authority	1,466,685 kWh	$320,515
Missouri	Tax Deduction for Home Energy Audits and Energy Efficiency Improvements	Missouri Department of Revenue		$315,125 claimed in the 2015 calendar year
Missouri	Energy Loan Program	Missouri Department of Economic Development (DED) Division of Energy (DE)	6,469,878 kWh 26,298 MMBtus	Estimated savings $783,091
Montana	Deduction For Energy-Conserving Investment	Department of Revenue	385,000 kWh (through April 2015)	
Nebraska	Dollar and Energy Savings Loans	Nebraska Energy Office	Residential only: 93,440 kW	$946,323 kWh & therms
Nevada	Home Energy Retrofit Opportunities for Seniors (HEROS)	Nevada Housing Division	1,654,319 kWh	$181,975
Nevada	Direct Energy Assistance Loan (DEAL) Program	Nevada Housing Division	94,383 kWh	

State	Title	Program administrator	Total energy savings	Total cost savings ($)
New Mexico	Sustainable Building Tax Credit (Corporate)	New Mexico Taxation & Revenue Department	Residential: 15,175,165 kBtus; Commercial: 31,518,226 kBtus	
New Mexico	Energy Efficiency & Renewable Energy Bond Program/Clean Energy Revenue Bond Program	New Mexico Finance Authority	20% savings minimum per project	
New York	New York Power Authority—Energy Services Programs for Public Entities	New York Power Authority (NYPA)	31,861,916 kWh	$10,209,575
Ohio	Energy Conservation for Ohioans (ECO-Link) Program	Office of the Ohio Treasurer	112,981 Mbtus	
Oregon	Residential Energy Tax Credit	Oregon Department of Energy	21315000 kWh 256,000 therms	$2,387,500 (from electric) $256,000 (from gas)
Oregon	Energy Conservation Tax Credits—Competitively-Selected Projects (Corporate)	Oregon Department of Energy	76,659,000 kWh	$7,730,900
Oregon	Energy Conservation Tax Credits—Small Premium Projects (Corporate)	Oregon Department of Energy	6,509,000 kWh	$828,900

State	Title	Program administrator	Total energy savings	Total cost savings ($)
Pennsylvania	Alternative and Clean Energy Program	Pennsylvania Department of Community and Economic Development (DCED) and the Department of Environmental Protection (DEP), under the direction of Commonwealth Finance Authority (CFA)	227,000 kWh/yr saved, 1,290,113 MMBtus/yr saved, 229,859 MWh generated/yr	
Pennsylvania	Alternative Fuels Incentive Grant	Pennsylvania Department of Environmental Protection (DEP)	2.6 million GGE displaced/yr	
Pennsylvania	Energy Efficiency Loan Program (Keystone HELP/WHEEL)	Pennsylvania Treasury Department, Renew Financial	587,374 kWh/yr and $58,737.40/yr	Origination loan value of $1,437,141.56
Pennsylvania	High Performance Building Incentives Program	Pennsylvania Department of Community and Economic Development (DCED) and the Department of Environmental Protection (DEP), under the direction of Commonwealth Finance Authority (CFA)	58,800 kBtus/yr saved	$2,529
Pennsylvania	Green Energy Loan Fund	The Reinvestment Fund, through a contract with Pennsylvania Department of Environmental Protection (DEP)	645,342 (2,202 MMBtus/yr)	

State	Title	Program administrator	Total energy savings	Total cost savings ($)
Rhode island	Efficient Buildings Fund	Rhode Island Infrastructure Bank		$3.3 million
Rhode island	Block Island Saves	Rhode Island State Energy Office	91,852 kWh and 283 MMBtus annual savings	$42,546 annual savings
Tennessee	Energy Efficient Schools Initiative—Grants	Energy Efficient Schools Initiative	Annual kWh savings for all grant recipients for which there is data is 41 million kWh/yr; cumulative savings is 164 million kWh (2012–2016)	Annual electricity savings for all grant recipients for which there is data is $4.1 million/yr; cumulative electricity savings is $16.4 million (2012–2016)
Tennessee	Pathway Energy Efficiency Loan Program (EELP)	Pathway Lending Community Development Financial Institution	Annual savings of 9,803,330 kWh from 2015 loans; cumulative annual savings for all projects is approximately 38,000,000 kWh	Annual savings of $1,032,602 from 2015 loans; cumulative annual savings for all projects funded to date is approximately $4,000,000
Tennessee	Energy Efficient Schools Initiative—Loans	Energy Efficient Schools Initiative	172 million kWh in cumulative savings for the 15 loans for which data is available	$17.22 million in cumulative savings through June 2016 for the 15 loans for which data is available
Tennessee	Bristol Energy Efficiency Assistance Program	Tennessee Office of Energy Programs (OEP)	14,063 kWh as of December 31, 2015	$1,275 as of December 31, 2015

State	Title	Program administrator	Total energy savings	Total cost savings ($)
Tennessee	Clean Tennessee Energy Grant Program	Tennessee Department of Environment & Conservation, Office of Sustainable Practices	To date, all projects report a total annual reduction of 32 million kWh and annual emissions reduction of 80 million pounds of carbon dioxide equivalent (CO2e)	To date, all projects report $3.1 million in energy and maintenance savings annually
Texas	LoanSTAR Revolving Loan Program	Texas State Energy Conservation Office	Cumulative site savings as of February 2016: 4,215,403,256 kWh electric; 15,833,890 MMBtus gas; 8,099,267 MMBtus chilled water	Total savings as of February 2016: $496,822,151
Vermont	Energy Loan Guarantee Program	Vermont Economic Development Authority	64,300 kWh annually	
Vermont	Sustainable Energy Loan Fund	The Vermont Economic Development Authority	2,144 MMBtus annually	
Vermont	Weatherization Trust Fund	State of Vermont Office of Economic Opportunity	25%, typical energy and associated cost reduction per home for heating	
Vermont	Thermal Energy and Process Fuel Efficiency Program	Vermont Economic Development Authority	64,300 kWh annually	

ACEEE excluded individual program budgets from the table above because this metric did not allow for a state-by-state comparison of financial incentives. We also attempted to collect incentive participation data, but most state respondents were unable to quantify the total number of eligible participants for each program. As a result, participation could not be expressed as a percentage, and we excluded these data from the table above.

JEA 2015 Solar RFP – Phase 2 Summary

Per the 2014 Solar Policy, JEA is seeking to add up to 38 MW of solar capacity, with at least 2 MW from small (500 kW or less) facilities. JEA previously awarded a total of 12 MW from Solar RFP - Phase 1. Our proposed lease of property off Normandy Blvd. will contribute an additional 5 MW. JEA intends to fill the remainder 21 MW through Solar RFP - Phase 2. Considering score, overall price, and other factors (see below), the following awards for Phase 2 have been made:

Phase 2 – Large Scale Solar – 19.5 MW

No.	Company	Project Name	$MW_{(AC)}$	Circuit Name	Score	$/MWh Year 1
1	**COX Radio**	Old Plank Road, Solar Farm	3*	Normandy T2	100	59.00
2	**National Solar**	Imeson Solar Farm	5	Imeson T1	77	79.00
3	**Inman Solar**	Simmons Road Solar	2*	Dinsmore T1	74	83.43
4	**Inman Solar**	Starratt Solar	5	Starratt T1	71	86.50
5	**SunEdison**	SunE Salisbury Road Solar	4.5*	Southpoint T2	71	87.50
TOTAL			**19.5**			

*Reflecting the allowable $MW_{(AC)}$ based on the circuit project will interconnect to, instead of proposed $MW_{(AC)}$

Phase 2 – Garden Scale Solar – 1 MW

No.	Company	Project Name	$MW_{(AC)}$	Circuit Name	Score	$/MWh Year 1
6	**Mirasol Fafco Solar**	Pipit	0.5	Ribault T1	69	64.00
7	**Mirasol Fafco Solar**	JTA Phillips Lot Solar Array	0.5	Philips T1	69	64.00
TOTAL			**1**			

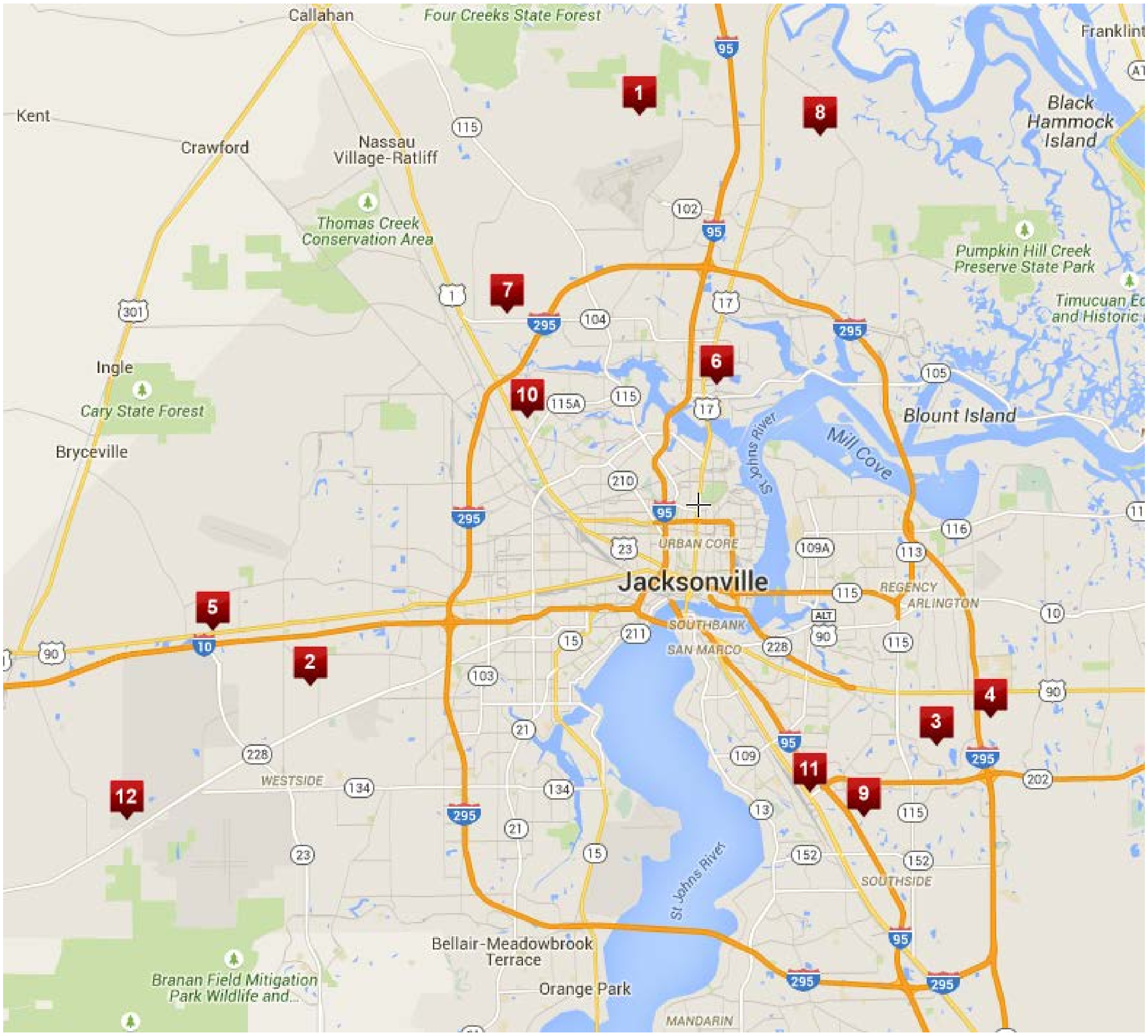
Phase 3 – 5 MW

JEA has identified property on the Cecil 389 circuit for which it expects to enter into a lease. JEA expects to issue the RFP in July 2015 for the construction of up to 5 MW solar PV for a PPA on the property.

Total (Phase 1~3) – 37.6 MW

No.	Company	Project Name	$MW_{(AC)}$	Circuit Name	Total MWh (Year 1)	$/MWh Year 1
1	**groSolar**	Montgomery Solar Farm	7	Beeghley 393	14,179	69.30
2	**Hecate Energy**	Blair Site	4	Normandy 361	8,454	62.41
3	**Hecate Energy**	Forest Road	0.5	Forest 216	1,056	63.88
4	**Hecate Energy**	UNF	0.5	Forest 215	1,056	64.27
5	**COX Radio**	Old Plank Road, Solar Farm	3	Normandy T2	5,088	59.00
6	**National Solar**	Imeson Solar Farm	5	Imeson T1	9,966	79.00
7	**Inman Solar**	Simmons Road Solar	2	Dinsmore T1	3,709	83.43
8	**Inman Solar**	Starratt Solar	5	Starratt T1	9,272	86.50
9	**SunEdison**	SunE Salisbury Road Solar	4.5	Southpoint T2	900	87.50
10	**Mirasol Fafco Solar**	Pipit	0.5	Ribault T1	900	64.00
11	**Mirasol Fafco Solar**	JTA Phillips Lot Solar Array	0.5	Philips T1	10,735	64.00
12	**TBD**	TBD	5	Cecil 389	TBD	TBD
TOTAL			**37.6**		**65,315**	**74.26**

The average cost for 32.6 MW from Phase 1 and 2 Solar RFP is $74.26/MWh (Year 1), with a 20-year average cost of $82.05/MWh.


Callahan
Four Creeks State Forest
Kent
Crawford
Nassau Village-Ratliff
Thomas Creek Conservation Area
Black Hammock Island
Pumpkin Hill Creek Preserve State Park
Timucuan Ec and Historic
Ingle
Cary State Forest
Bryceville
Blount Island
Mill Cove
St Johns River
URBAN CORE
Jacksonville
REGENCY
ARLINGTON
SOUTHBANK
SAN MARCO
WESTSIDE
SOUTHSIDE
Bellair-Meadowbrook Terrace
Orange Park
MANDARIN
Branan Field Mitigation Park Wildlife and...
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JEA 2015 Solar PV RFP

JEA Solar PV RFP - Phase 2 - Result

Company Name	Project Name	$MW_{(AC)}$	Circuit	Score
COX Radio, Inc.	Old Plank Road, Solar Farm	3*	Normandy T2	100
National Solar, LLC.	Imeson Solar Farm	5	Imeson T1	77
Inman Solar, Inc.	Simmons Road Solar	2*	Dinsmore T1	74
Inman Solar, Inc.	Starratt Solar	5	Starratt T1	71
SunEdison	SunE Salisbury Road Solar	4.5*	Southpoint T2	71
Mirasol Fafco Solar Inc.	Pipit	0.5	Ribault T1	69
Mirasol Fafco Solar Inc.	JTA Phillips Lot Solar Array	0.5	Philips T1	69
TOTAL		**20.6**		

Evaluation Criteria

Projects were scored based on

i. Price (90%)

ii. Community Outreach (5%)

iii. JSEB (5%)

JEA 2015 Solar PV RFP

Solar Farm

Company Name	Project Name	$MW_{(AC)}$	Circuit	Allowed $MW_{(AC)}$	Score: Price (90 Pts)	Score: Community (5 Pts)	Score: JSEB (5 Pts)	Score: TOTAL (100 Pts)	Comment
Borrego Solar Systems, Inc.	Setzer Solar Project	5.0	Garden City T2	5.0	46	5	5	56	
Borrego Solar Systems, Inc.	Old Kings Solar	2.0	Pickettville T1	2.0	46	5	5	56	
Borrego Solar Systems, Inc.	Beaver Solar	2.0	Normandy T2	3.0	45	5	5	55	
Borrego Solar Systems, Inc.	5705 Solar	2.0	Normandy T1	6.5	43	5	5	53	
Borrego Solar Systems, Inc.	Bostwick Solar	3.0	Garden City T2	5.0	42	5	5	52	
Coronal Development Services	Old Plank Solar Center	5.0	Normandy T2	3.0	70	5	5	80	Interconnect to Normandy T2, which can only allow 3 $MW_{(AC)}$.
COX Radio, Inc.	Old Plank Road, Solar Farm	5.0	Normandy T2	3.0	90	5	5	100	Interconnect to Normandy T2, which can only allow 3 $MW_{(AC)}$.
Hanwha Q-Cells	Hanwha Q Cells JEA Solar 1	5.0	Garden City T2	5.0	65	5	5	75	
Hecate Energy LLC *	Horne 5	5.0	Normandy T1	6.5	48	5	5	58	
Hecate Energy LLC *	Starrat Solar	5.0	Starratt T1	5.0	57	5	5	67	
Inman Solar, Inc.	Beaver Street Solar	3.0	Normandy T2	3.0	64	5	5	74	
Inman Solar, Inc.	Lem Turner Solar	5.0	Garden City T2	5.0	64	5	5	74	
Inman Solar, Inc.	Starratt Solar	5.0	Starratt T1	5.0	61	5	5	71	
Inman Solar, Inc.	Simmons Road Solar	2.8	Dinsmore T1	2.0	64	5	5	74	Location is actually to Dinsmore T1, which can only allow 2 $MW_{(AC)}$.
National Solar, LLC.	Imeson Solar Farm	5.0	Imeson T1	5.0	67	5	5	77	
SunEdison	SunE Cisco Gardens Solar	5.0	Normandy T2	3.0	61	5	5	71	
SunEdison	SunE Salisbury Road Solar	5.0	Southpoint T2	4.5	61	5	5	71	Interconnect to Southpoint T2, which can only allow 4.5 $MW_{(AC)}$.

Solar Garden

Company Name	Project Name	$MW_{(AC)}$	Circuit	Allowed $MW_{(AC)}$	Score: Price (90 Pts)	Score: Community (5 Pts)	Score: JSEB (5 Pts)	Score: TOTAL (100 Pts)	Comment
Hecate Energy LLC *	Horne 500 A	0.5	Normandy T1	6.5	38	5	5	48	
Hecate Energy LLC *	Horne 500 B	0.5	Normandy T1	6.5	38	5	5	48	
Hecate Energy LLC *	UNF 500 A	0.5	Forest	4.5	20	5	5	30	
Hecate Energy LLC *	UNF 500 B	0.5	Forest	4.5	20	5	5	30	
Inman Solar, Inc.	Catoma Solar	0.5	Firestone T2	7.5	47	5	5	57	
Inman Solar, Inc.	Necia Solar	0.5	Firestone T1	1.0	47	5	5	57	
Mirasol Fafco Solar Inc.	Everbank Field Solar Array	0.7	?	?	45	5	5	55	
Mirasol Fafco Solar Inc.	JTA Phillips Lot Solar Array	0.5	Phillips T1	3.5	59	5	5	69	
Mirasol Fafco Solar Inc.	Pipit	0.5	Ribault T1	2.0	59	5	5	69	
SunEdison	SunE Cisco Gardens Solar	0.5	Normandy T2	3.0	48	5	5	58	

***NOTE:**
(1) Pricing scores are based on prices that assumes **No Tax Abatement**

JEA 2015 Solar PV RFP

Solar Farm

Company Name	Project Name	$MW_{(AC)}$	Score: Price (90 Pts)	Score: Community (5 Pts)	Score: JSEB (5 Pts)	Score: TOTAL (100 Pts)	Circuit
COX Radio, Inc.	Old Plank Road, Solar Farm	3*	90	5	5	100	Normandy T2
National Solar, LLC.	Imeson Solar Farm	5	67	5	5	77	Imeson T1
Inman Solar, Inc.	Simmons Road Solar	2*	64	5	5	74	Dinsmore T1
Inman Solar, Inc.	Starratt Solar	5	61	5	5	71	Starratt T1
SunEdison	SunE Salisbury Road Solar	4.5*	61	5	5	71	Southpoint T2

Solar Garden

Company Name	Project Name	$MW_{(AC)}$	Score: Price (90 Pts)	Score: Community (5 Pts)	Score: JSEB (5 Pts)	Score: TOTAL (100 Pts)	Circuit
Mirasol Fafco Solar Inc.	Pipit	0.5	59	5	5	69	Ribault T1
Mirasol Fafco Solar Inc.	JTA Phillips Lot Solar Array	0.5	59	5	5	69	Philips T1

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U.S. Department of Energy

Q4 2016/Q1 2017 Solar Industry Update

Robert Margolis, NREL
David Feldman, DOE
Daniel Boff, DOE

energy.gov/sunshot

April 25, 2017

NREL/PR-6A20-68425
NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, operated by the Allilance for Sustainable Energy, LLC.

Executive Summary

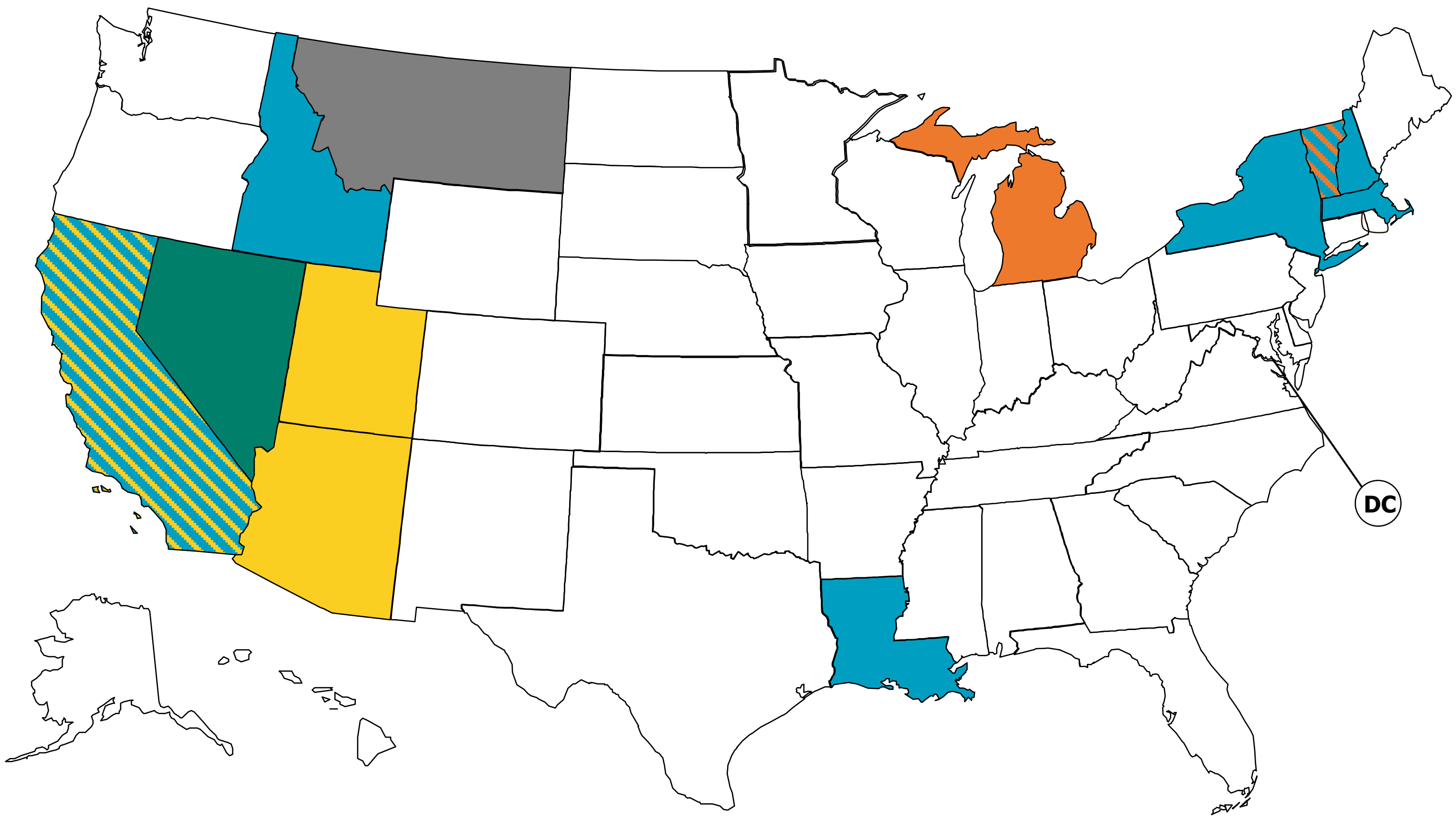
- The United States installed 14.8 GW_{DC} of PV in 2016, an increase of 97% from 2015, representing ~$30 billion in deployed capital, along with another $2.2 billion in U.S.-manufactured PV products.
  - The United States ranked 2nd globally in annual PV installations behind China.
  - Cumulatively the United States had installed 40.4 GW_{DC} at the end of 2016 and has installed over 1.25 million PV systems.
  - 1.4% of electricity generated in the United States in 2016 came from solar facilities.
  - While composing only 3% of U.S. installed electric generation capacity, solar compromised the largest share of electric generation capacity additions in 2016 (~40%).
- China installed approximately 34 GW of solar in 2016, 77 GW cumulatively, and now has more solar capacity than the second largest market, Japan, by 34 GW.
- In 2015, three states enacted net metering changes that lowered exported energy credit to below retail rates; however, seven states increased their net metering cap—there are now 22 states with NEM regulations, studies or proceedings pending.
- In Q4 2016 residential installation costs (excluding SG&A) for two of the leading firms was around $2.05/W with total costs ranging from $3.0/W to $3.5/W.
- PV modules continue their sharp decline in price from the second half of 2016 with many analysts estimating module ASP to be around $0.35/W.
  - These low prices caused global module manufacturers to have their sharpest decline in gross margin since 2012.

A list of acronyms is available at the end of the presentation.

Agenda

- State and Federal Updates
- Global Market Updates
- U.S. Deployment
- U.S. Pricing
- Global Manufacturing
- Component Pricing
- Market Activity

Legislative/Regulatory Action for Net-Metering Effecting PV Enacted in 2016



- NEM Cap Increased (7 States)
- NEM Rule Or Process Changes (4 States)
- Solar credited between wholesale and retail rate (3 States)
- NEM Legislation Passed (2 States)
- NEM Restored (1 State)
- Solar Credited at Wholesale Rates or Below (0 States)

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Source: Meister Consultants Group, *50 States of Solar: Net Metering Quarterly Update* (Q4 2016).

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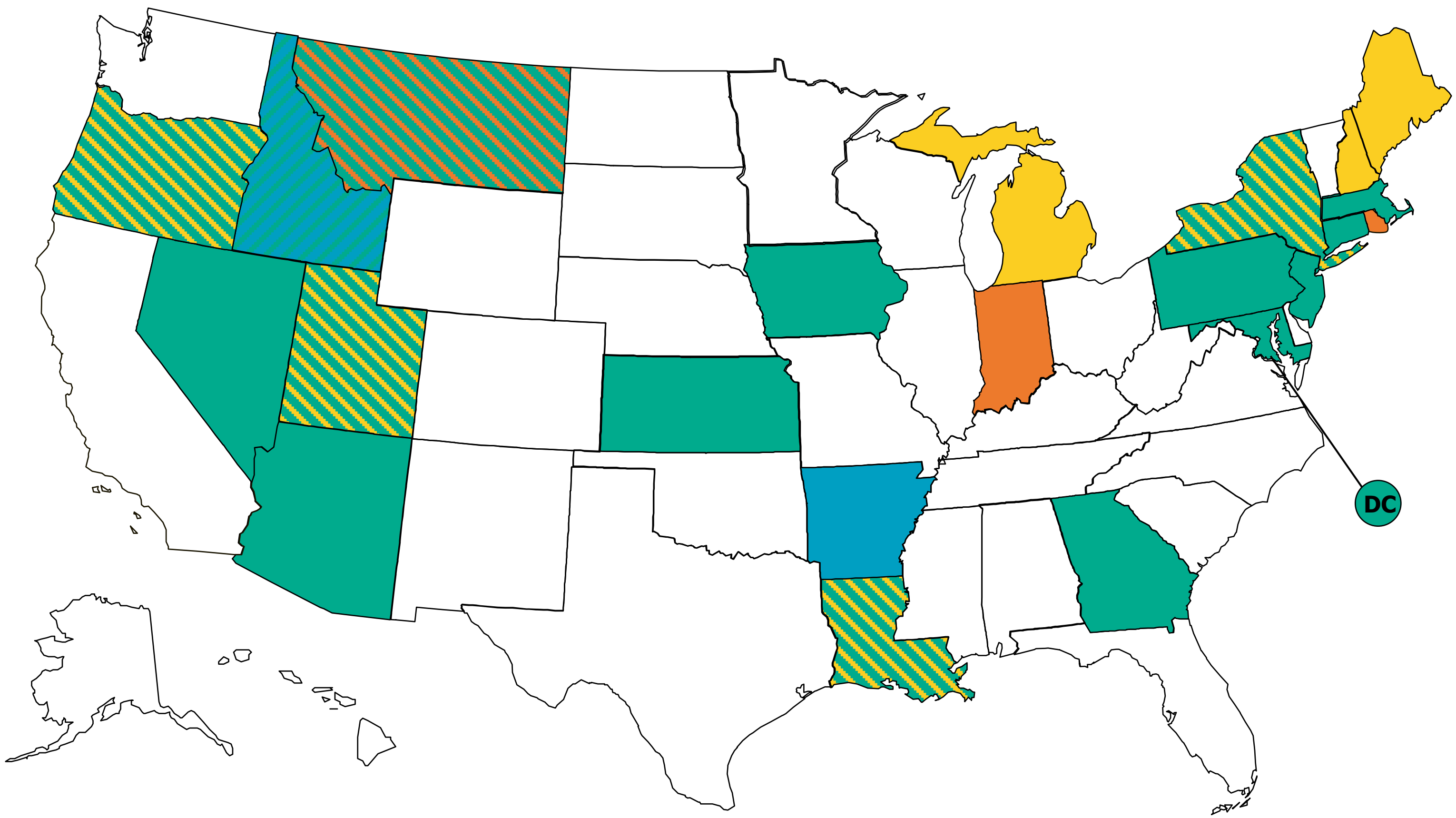
States with Pending NEM Regulations, Studies or Proceedings



Pending NEM Legislation (2 States)

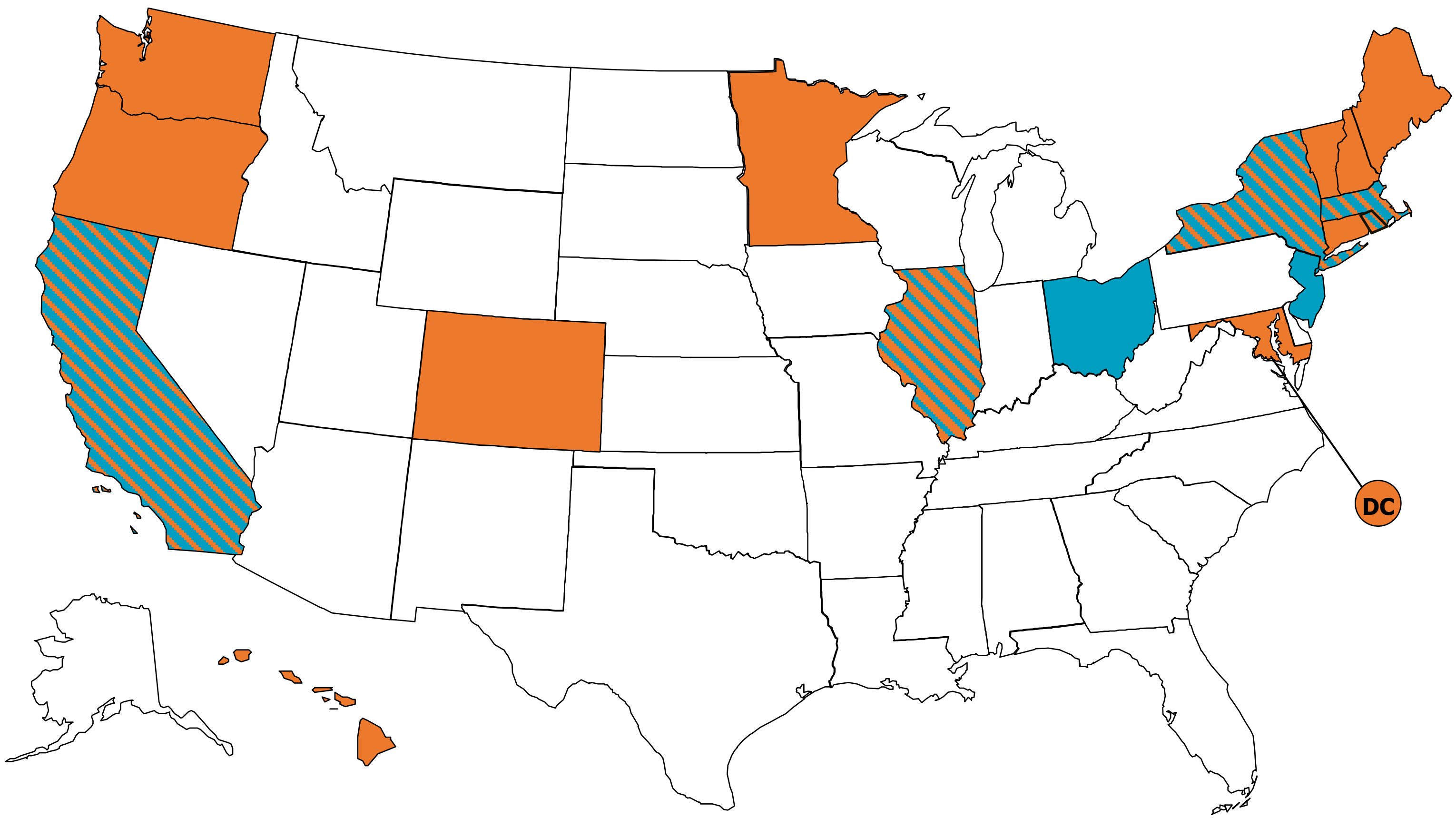
Active NEM Bill in State Legislature (3 States)

Pending Commission Proceeding or Docket (7 States)

DG Solar Valuation Study in 2016 (16 States)

Source: Meister Consultants Group, *50 States of Solar: Net Metering Quarterly Update* (Q4 2016).

Community Solar and Community Choice Aggregation



Community Solar Enabled (15 States)

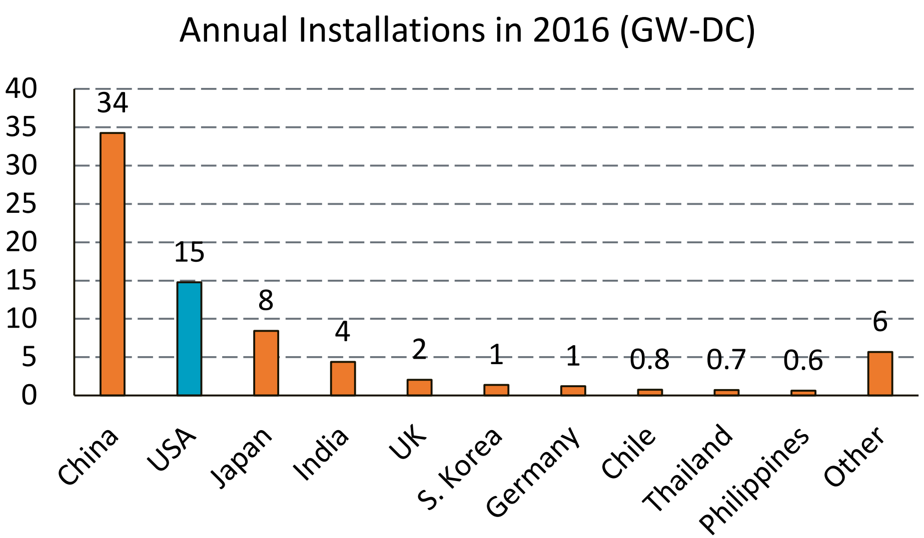
Community Choice Aggregation (7 States)

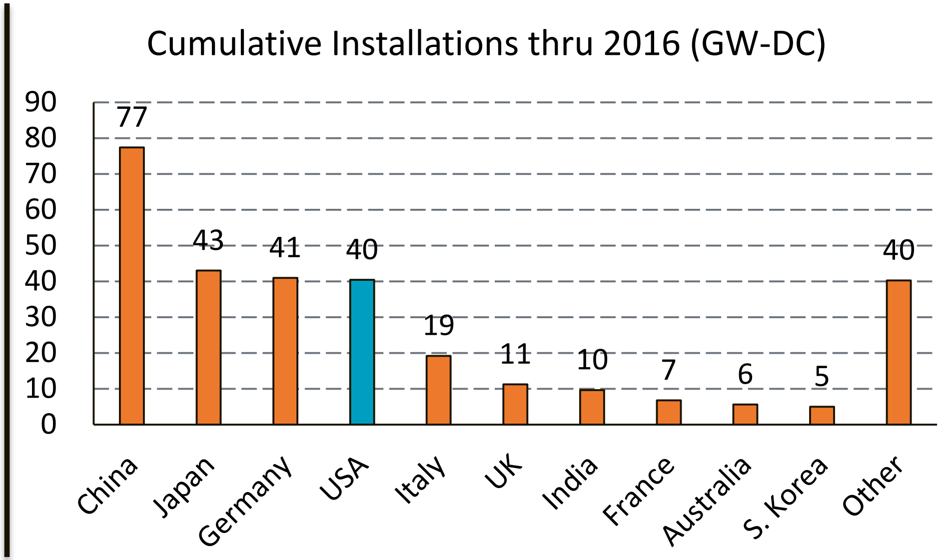
Source: Meister Consultants Group, *50 States of Solar: Net Metering Quarterly Update* (Q4 2016)., National Council of State Legislatures.

Agenda

- State and Federal Updates
- Global Market Updates
- U.S. Deployment
- U.S. Pricing
- Global Manufacturing
- Component Pricing
- Market Activity

Top Ten PV Markets by Country



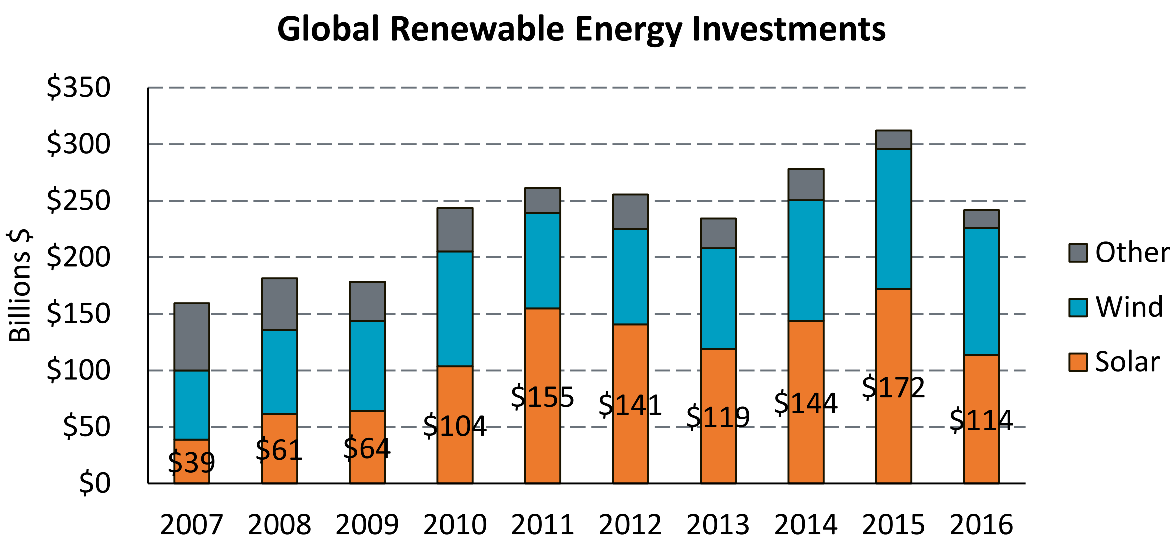


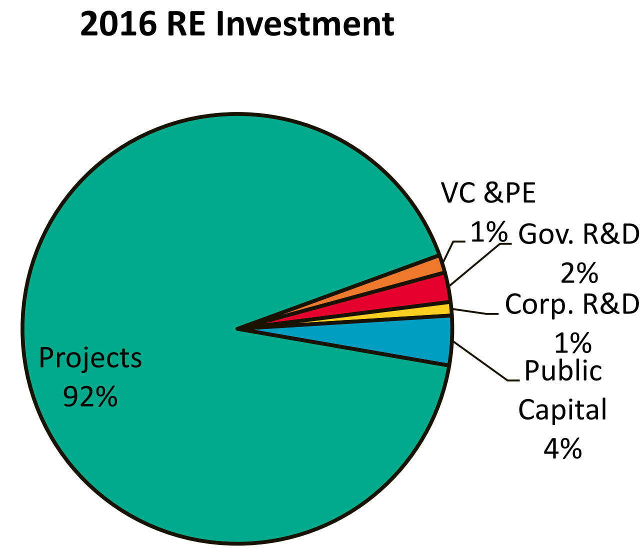
- At the end of 2016, global PV installations reached 299 GW_{DC}, up from 225 GW_{DC} in 2015.
  - An annual increase of 74 GW_{DC}
  - In 2001, there was only 1 GW of cumulative installations; the industry has thus grown by a factor of 298.
- Globally, the United States installed the second most PV capacity in 2016 and is now one of the top four markets in cumulative capacity—including CSP, it is nearing the second largest global solar market.
- The top ten markets represented 92% of annual PV installations in 2016.
  - China represented 46% of annual global installations in 2016.
- Despite a large concentration of installs in a few markets, many new markets are expanding around the world
  - From 2012 to 2016, Asian countries (other than China, Japan, and India) installed 8.6 GW, African countries installed 2.1 GW and South American countries installed 1.8 GW.

SunShot U.S. Department of Energy

Source: All statistics from: IRENA "Renewable Capacity Statistics 2017," except United States from (GTM Research & SEIA: SMI 2016 Year-in-Review," and Japan from RTS Corporation.

Global Renewable Energy Investment

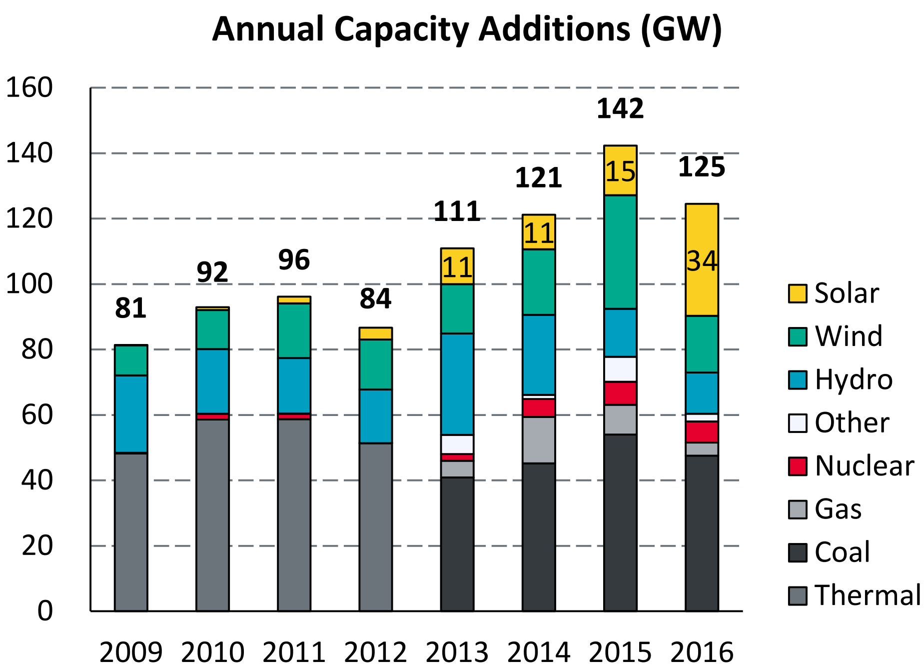


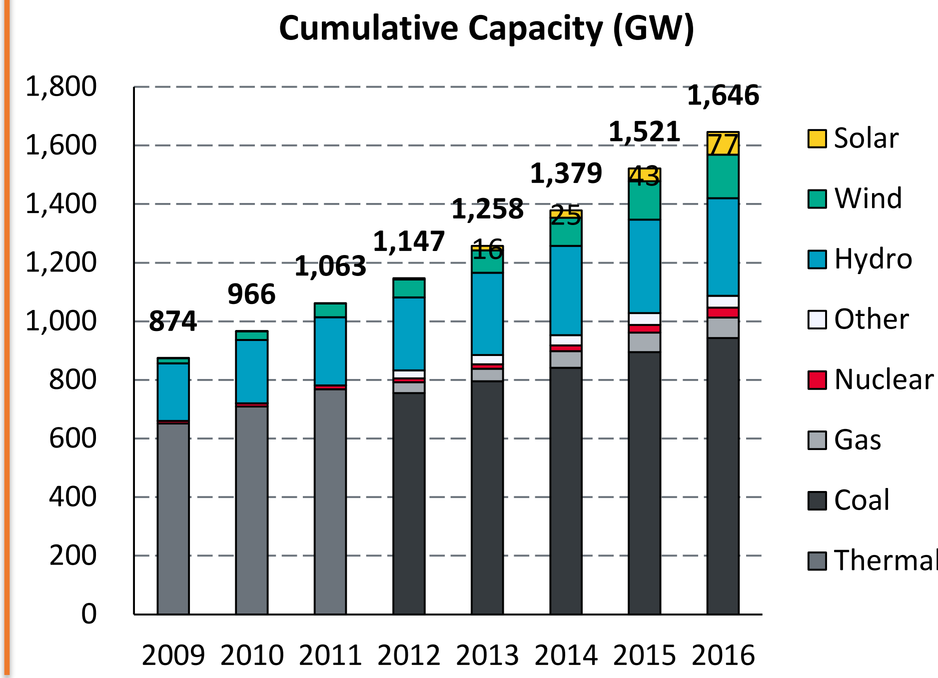


- $242 billion of investments were made in the renewable energy industry in 2016, down 23% y/y.
  - Approximately $114 billion of investments went into the solar industry, down 34%.
- The drop in investments belies the fact that there was a record level of renewable power capacity added in 2016 (~140 GW).
  - Renewable energy project costs dropped by more than 10% in 2016.
  - Many of the projects installed in 2016 were financed in 2015 and there was a slowdown in investments in China, Japan, and the developing world.
- The vast majority of investments dollars went to projects, rather than company development and R&D.
- Solar R&D investment fell 20% to $3.6 billion ($1.6 billion from corporate R&D, $2.0 billion from government R&D) mostly due to a 39% reduction in corporate R&D.

Source: Global Trends in Renewable Energy Investment: 2017. FS-UNEP Collaborating Centre/BNEF.

Chinese Generation Capacity Additions by Source





- In 2016, solar contributed 28% to new generation capacity in China (34 GW) and 5% of cumulative capacity (77 GW).
- Since 2009 China has doubled its installed electric generation capacity, and at the same time reduced the percentage of total thermal capacity, from 76% to 64%.
  - From 2010 to 2016, new thermal generation capacity as a percent of total new capacity was reduced from 63% to 43%.

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Source: China Electric Council, accessed 04/11/17.

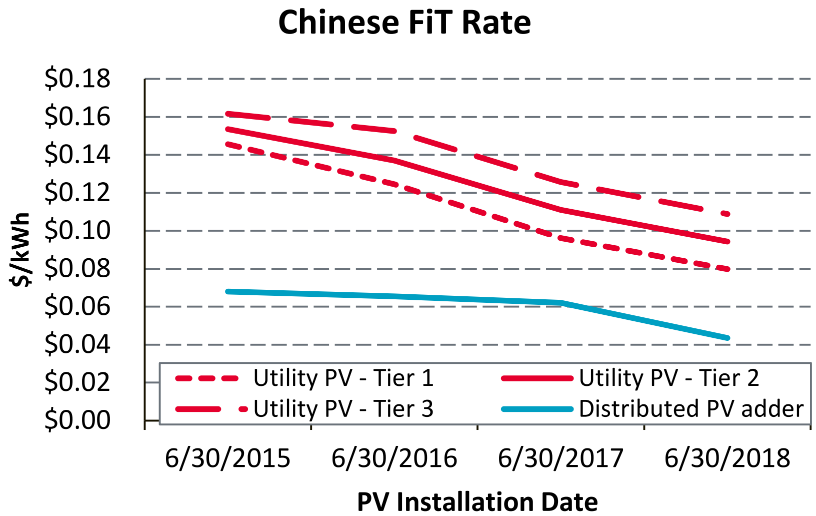
China Update

- China reported installing 34 GW of PV in 2016, compared to 15 GW in 2015, bringing its cumulative total installed PV capacity to 77 GW.
  - In 2016, 30 GW of installations came from power stations and 4 GW from distributed PV systems—representing a similar proportion to previous years.
- China reduced its five-year plan PV installation target to 105 GW (from 150 GW), leaving 30 GW to be installed by 2020; however, the previous target was seen as a ceiling and the new target is viewed as a floor.
  - China also has a target of 5 GW of CSP by 2020; however, unlike PV, it has fallen short of previous CSP targets.
  - In December 2016, China also revised its 105 GW target which previously included a 60 GW DG PV target; thus far the majority of PV installations in China have been utility-scale.
  - Not included in the installation target are the Top-Runner and Poverty Alleviation Programs:
    - The Poverty Alleviation Program has the goal of installing solar panels on the roofs of 2 million poor families by the end of 2020.
    - The Top-Runner program aims to accelerate PV technology improvement by setting module efficiency standards.
  - Analyst projections of 2017 Chinese PV deployments range from 15 GW to 30 GW, which would still make it the largest PV market by a wide margin.

Note: Some analysts believe that a portion of the 34 GW of reported installations in 2016 were actually built in 2015.
Source: BNEF (03/30/17); CleanTechnica (12/09/16); Digitimes (03/28/17); Mercom (01/23/17); UBS (03/27/17).

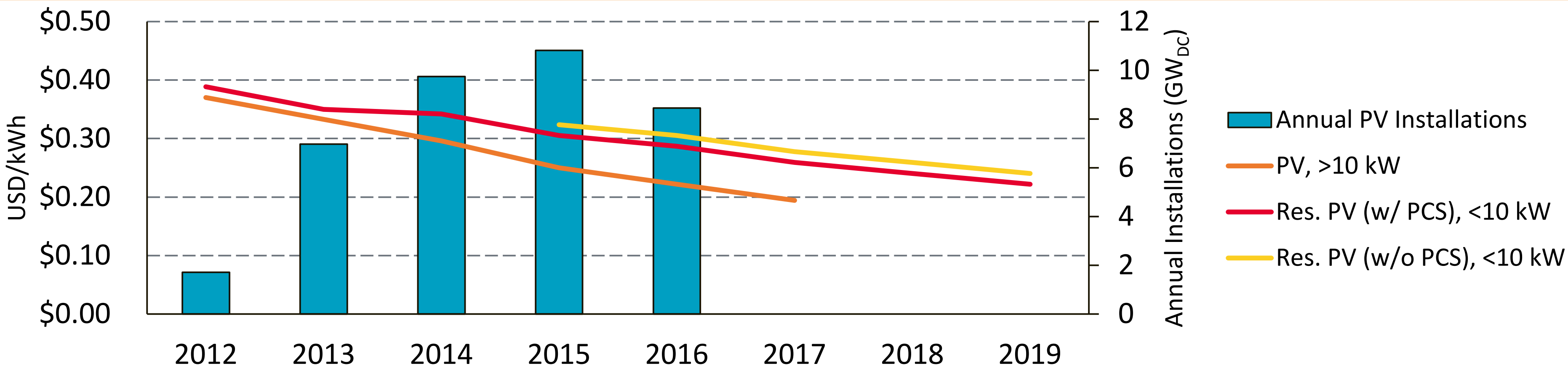
China Update (cont.)

- 22 GW of the 34 GW of PV projects built in 2016 were installed in the first half in order to qualify for a higher FiT; Chinese deployment picked up again in 2016 with the announcement of a 13%-19% FiT cut set to take effect in July 2017, as well as the reduction in module pricing.
  - In 2017, some installers are expected to interconnect PV systems in H1 before all of the system is built to receive the higher FiT.
- China is introducing a voluntary REC program for which PV projects can register; they will decide in 2018 whether to make it mandatory.
  - Under the program projects receive payments for RECs for energy, in lieu of FiT payments, which cannot exceed FiT rates. Currently, project owners often wait two years to receive FiT payments, so the REC program may actually improve project cash flow.
- Chinese developers are focusing on projects closer to population centers for easier interconnection; however, they face higher land costs, including taxes on agricultural land.



Source: BNEF (03/30/17); CleanTechnica (12/09/16); Digitimes (03/28/17); Mercom (01/23/17); UBS (03/27/17).

Japan Update

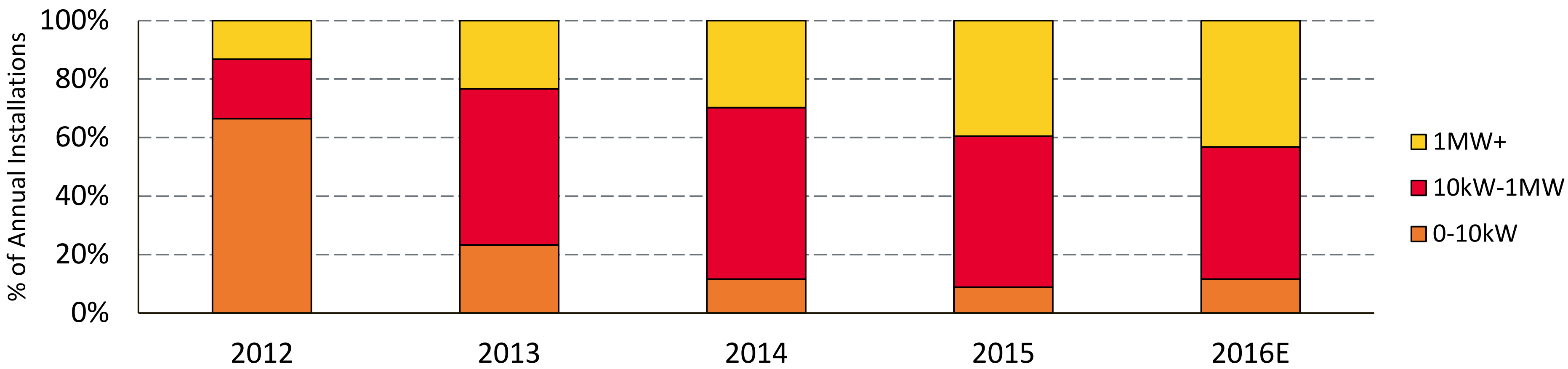


- Japan installed approximately 8.5 GW$_{DC}$ of PV in 2016, compared to 10.8 GW$_{DC}$ in 2015, surpassing Germany as the country with the second highest total PV capacity, with 43 GW.
  - PV represented 4.3% of electricity production in 2016 in Japan—up from 2.7% in 2015.
  - PV installations are expected to fall again in 2017 to ~7.5 GW.
- In March 2017 Japan announced revisions to its FiT program:
  - 10-year FiT for residential systems < 10 kW and without power controlling systems (PCS) will drop from JPY31(~$0.26) to JPY28 (~$0.24) in EY 2017, JPY26 in EY 2018, and JPY24 in EY 2019.
  - 20-year FiT for systems >10 kw began at JPY42 (~$0.36)/kWh in 2012 and fell to JPY24 (~$0.20)/kWh in April 2016 will drop to JPY21 (~$0.18) in April 2017 (when energy year starts).
  - Starting in EY 2018, Japan will have an auction mechanism for PV systems above 2 MW in size.
  - There have been far fewer FiT applications with the lower FiT rates; however, there are still over 45 GW of non-commissioned PV projects.

Notes: Japanese energy year starts in April. Values of feed-in-tariff (FiT) in chart are representative of energy year (EY); installations are representative of calendar year. In EY 2015 the FiT for Japanese PV systems larger than 10 kW was 29 JPY/kWh from April to June. JPY/USD exchange rate is held at 0.00925 for all years.

Sources: BNEF (01/30/17; 02/17/17); EnergyTrend (03/22/17); IEA PVPS NSR Japan (September 2016); Mercom (12/26/16; 01/23/17).

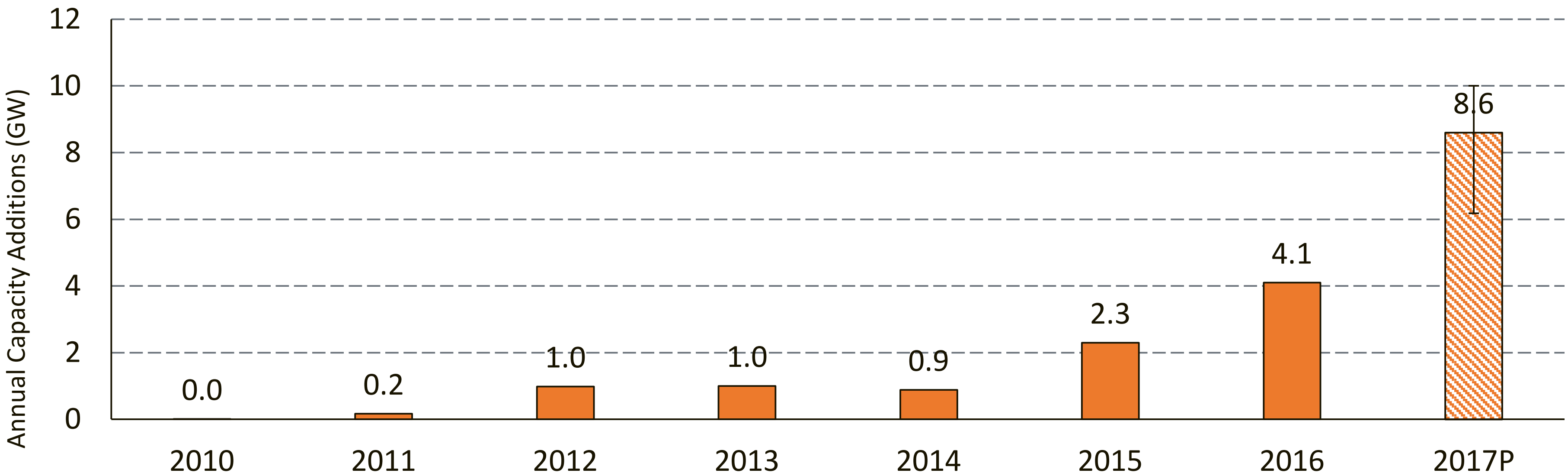
Japan Update (cont.)



- Japan's PV market consisted of primarily residential systems before the FiT; however, it has since transitioned to installing larger-sized plants.
- Japanese PV developers have expressed concern over high system prices and the risk of energy curtailment.
  - To date, curtailment has only occurred in two places—both islands—and typically on holidays with low-levels of demand.
  - In April 2017, Japan announced a plan to lower the cost of batteries installed with solar on home-rooftops by as much as 70% by 2021.
- Japanese PV manufacturing has fallen since 2013, from approximately 3.6 GW to approximately 2.7 GW in 2016.

Sources: BNEF (01/30/17; 02/17/17); EnergyTrend (03/22/17); Mercom (12/26/16; 01/23/17); SPV Market Research (April 2017).

India Update



- India has substantially increased PV deployment after years of uneven growth.
- The country installed roughly 4.1 GW of solar in 2016 (up from 2.3 GW in 2015).
  - Capacity additions have doubled every year since 2014, and analysts expect it to double again in 2017.
  - Solar currently represents about 1% of the nation's electricity load.
- The country is working to create a more effective policy environment, with analysts projecting between 6 GW and 10 GW of deployment in 2017.

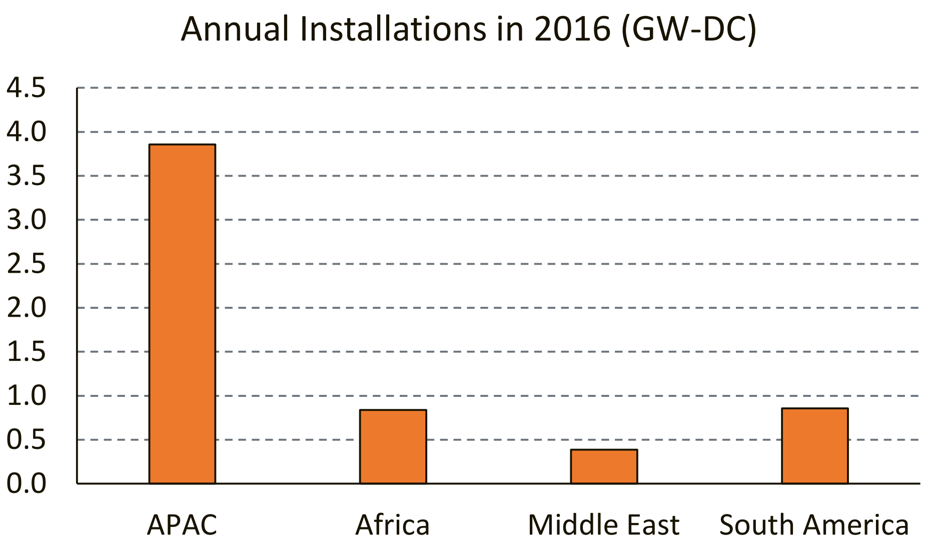
Sources: Mercom (1/2/17; (2/24/15); 2017 analyst projections from slide 18.

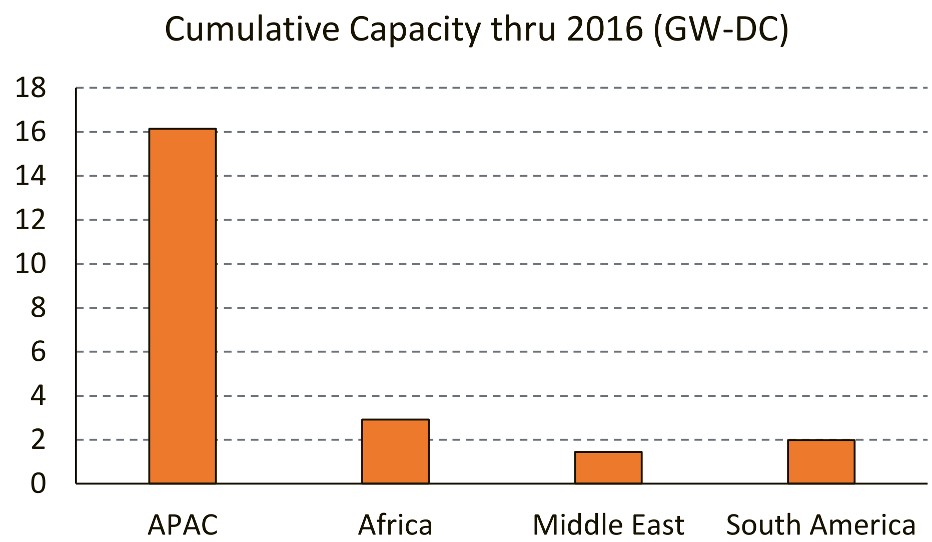
India Update

- **India has set aggressive targets for solar, but has had difficulty meeting interim goals.**
  - The country has a goal to deploy 100 GW of PV by 2022, but had only installed 10 GW of total capacity at the end of 2016.
  - Developers have indicated that frequently changing policies have inhibited growth in the short term.
- **India has looked toward a variety of methods to incentivize solar deployment.**
  - Utility scale deployment has also been driven by solar parks (right of way zones with transmission access). The government has set a goal of 40 GW (recently doubled from 20 GW) of utility scale PV deployment in solar parks.
    - India was one of the first countries to use tenders (reverse auctions) to facilitate PV deployment.
  - The nation has relatively generous SRECs that were priced between $86 and $52/SREC in 2016; these prices are expected to decrease substantially in 2017.
  - Some states are also providing subsidies for net metered rooftop systems, and the national government has set a goal of 40 GW of rooftop PV by 2022.
  - India has indicated that while it will incentivize PV deployment, it will not subsidize domestic manufacturing.
- **PV deployment targets are closely tied to economic development targets.**
  - Electricity demand could quadruple by 2040, as the country's population and economy expand.
  - As over 300 million Indians do not have access to the electricity grid, the strategy of employing both centralized and DG PV is seen by the government as a way to electrify rural communities while curbing pollution in urban centers.

Sources: Mercom (3/30/17; 3/24/17; 3/10/17; 3/6/16), World Bank (6/30/16); PV Tech (6/2/15), CleanTechnica (2/30/17); Sivaram, "The Global Warming Wild Card"

Emerging Market Update

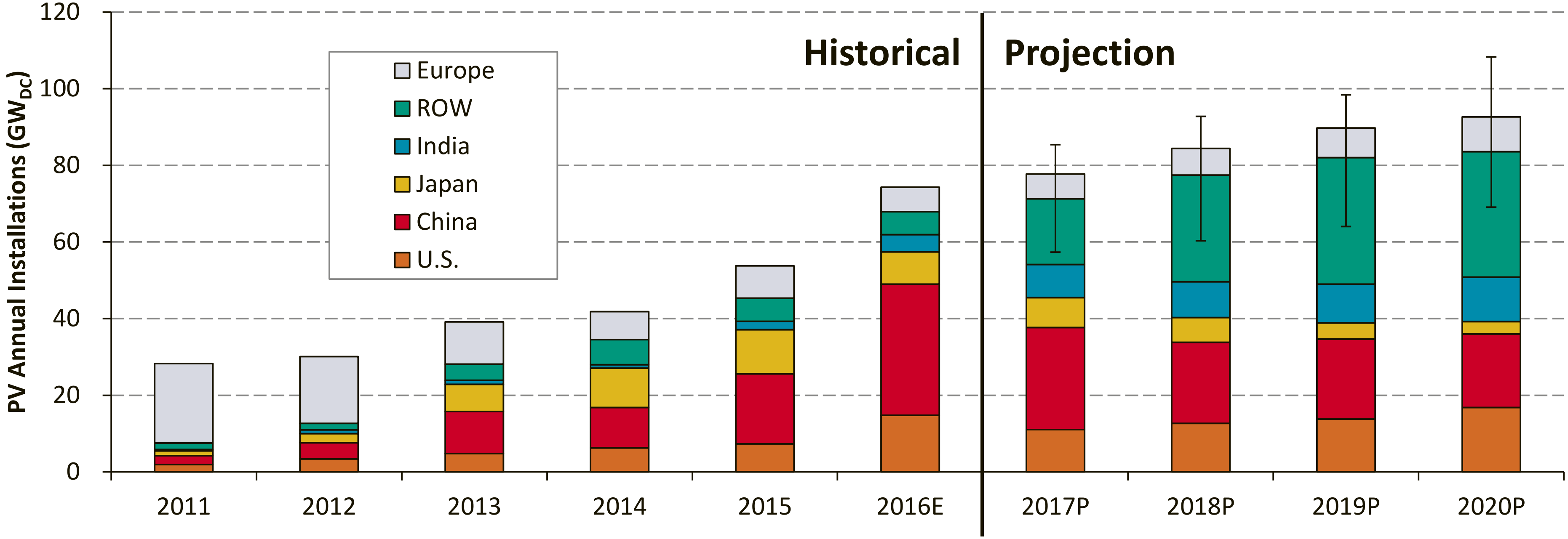




- PV Deployment continues to be driven by a few nations, but some smaller countries have reached GW levels of deployment.
- South Korea has set ambitious goals for PV, announcing $28 billion of investment into renewables by 2020; 5 GW of PV capacity were installed in 2016.
- Chile remains the market leader in South America, and it has begun construction on the largest solar park in the Americas, a 754-MW set of projects that will begin generating in 2018.
- Nigeria has signed over 1 GW of PPAs for solar projects, that are beginning construction in 2017.
- Saudi Arabia issued tenders for 700 MW of solar and wind projects, as part of a $50 billion push to cut oil consumption.

Source: All statistics from: IRENA "Renewable Capacity Statistics 2017," Bloomberg (4/17/17); CleanTechnica (4/17/17), PV Magazine (7/7/16).
Note: APAC includes all listed IRENA countries in Asia and Oceana, except China, India, and Japan.

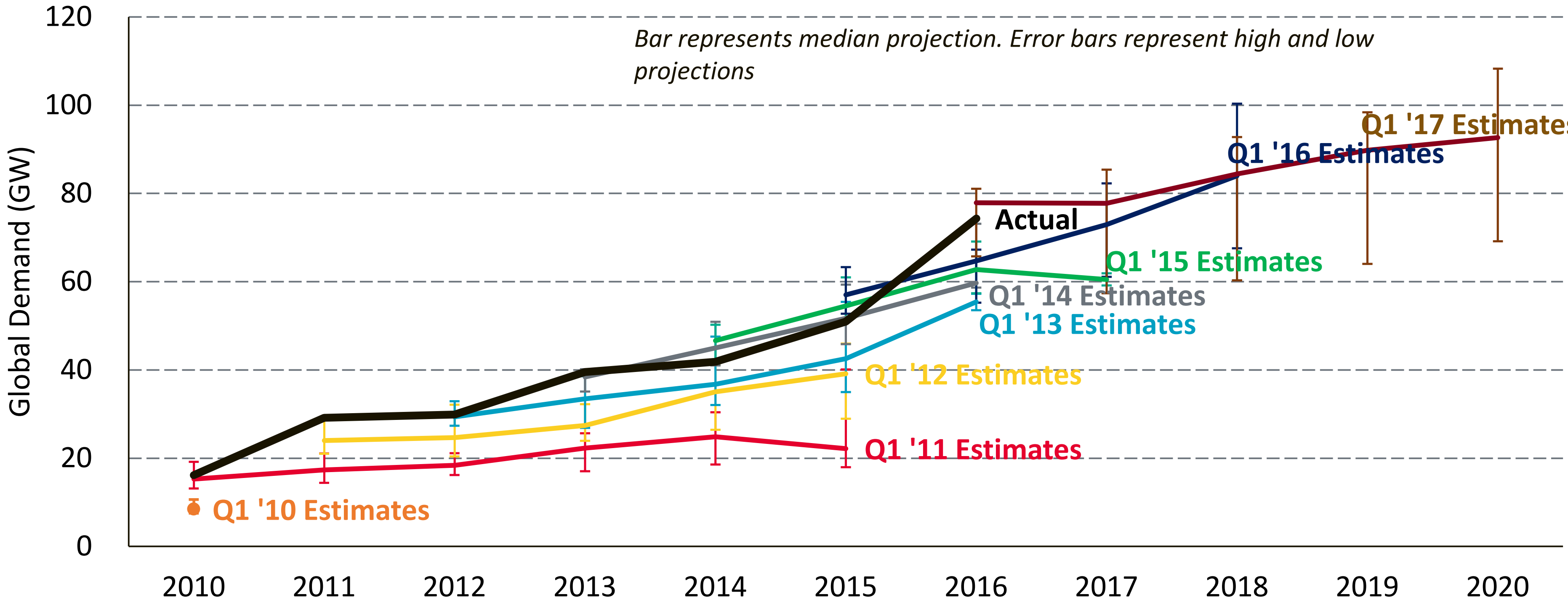
Annual Global PV Demand



- Analysts recently estimated that approximately 75 GW of PV was installed globally in 2016 (54 GW in 2015), bringing the cumulative total to ~300 GW.
  - China (~34 GW) and the United States (~15 GW) were the two largest markets in 2016.
- Annual global installations are projected to grow to be 69 GW–109 GW by 2020.
  - The median analyst figures estimate that 380 GW of PV will be installed globally from 2017 to 2020, more than doubling current installed capacity.
  - The majority of the growth is expected to come from emerging markets (ROW).

Note: E = estimate. P = projection. Bar represents median projection. Error bars represent high and low projections.
Sources: 2016 figures from slide 8. Other data displayed represent the median figures from the following sources: BNEF (02/17/17); Cowen & Co. (10/16/16); Deutsche Bank (04/24/17, 03/09/17, 10/19/16); Goldman Sachs (01/02/17), GTM Research (January 2017); IHS Technology (03/31/17); UBS (January 2017).

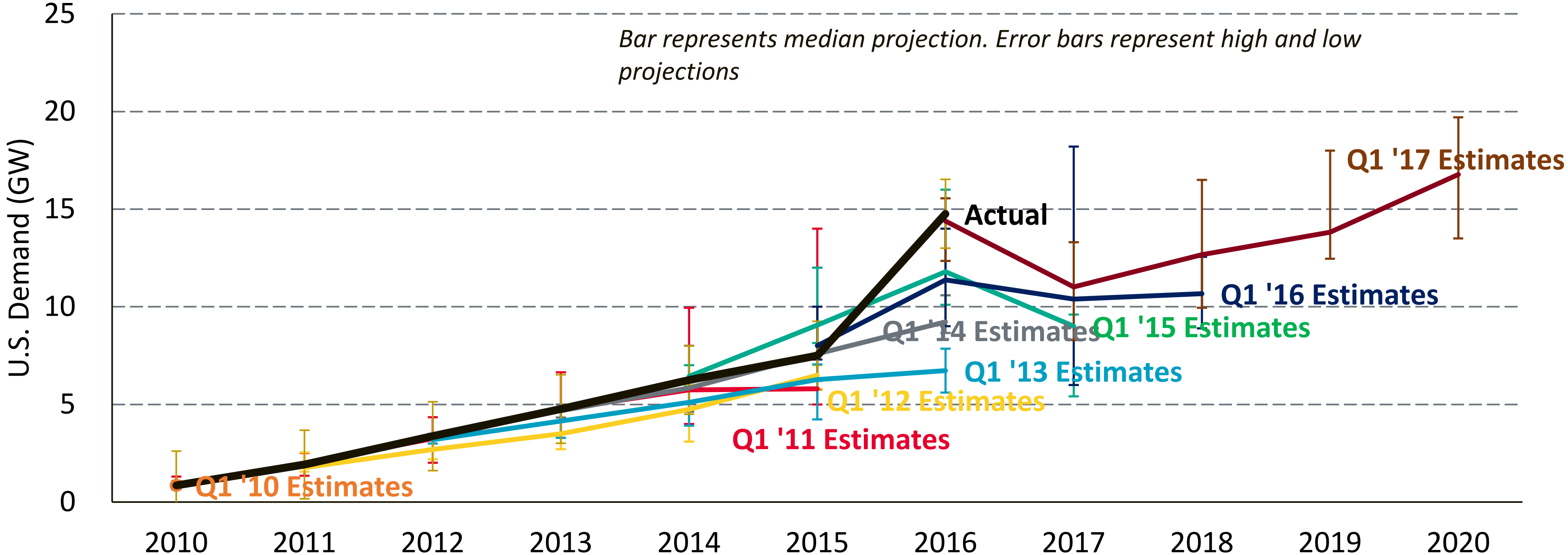
Historical Projections vs. Actual Global PV Deployment



- Analysts have historically underestimated future PV deployment, particularly in years with large changes in deployment (e.g., 2011, 2016) and for longer-term projections.
  - The median analyst projection, made in Q1 2011, for global deployments in 2015 was 22 GW and the highest projection that period was 40 GW—actual deployment was approximately 50 GW in 2015.

Notes: Analyst projections may vary due to differing methodologies of projecting ***installations*** or ***shipments***. Median, maximum, and minimums may also vary because of the differing set of analyst projections for each year. Q1 estimates also include estimates made in Q4 of the previous year.
Sources: 56 separate estimates from 20 institutions.

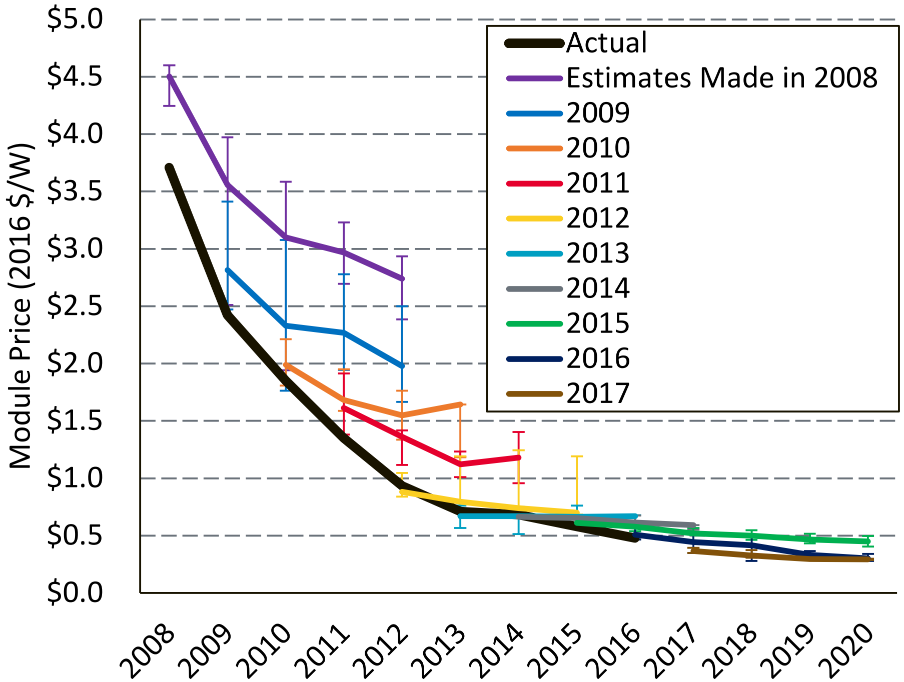
Historical Projections vs. Actual U.S. PV Deployment

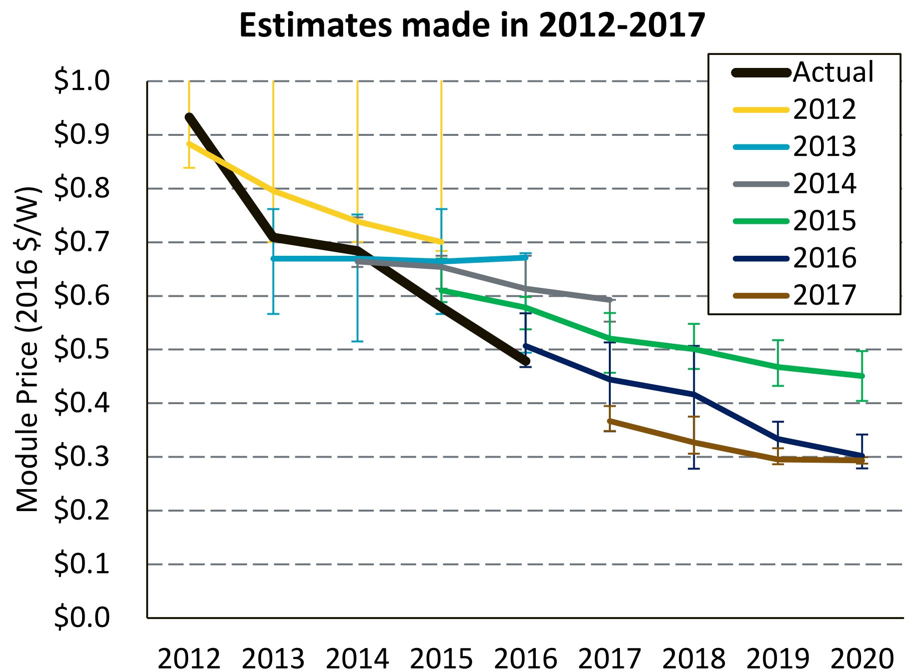


- Due to relatively stable federal policies in the United States, the median projections were relatively close to actual deployment.
- Despite knowing of the potential expiration of the ITC in 2016 most analysts historically underestimated PV deployment in that year.

Notes: Analyst projections may vary due to differing methodologies of projecting ***installations*** or ***shipments***. Median, maximum, and minimums may also vary because of the differing set of analyst projections for each year. Q1 estimates also include estimates made in Q4 of the previous year.
Sources: 56 separate estimates from 20 institutions.

Historical Projections vs. Actual U.S. Module ASP





- Historical deployment likely exceeded expectations because PV pricing has dropped faster than historically expected.
- A rapid drop in module price from 2008 to 2012 caught many in the industry by surprise causing the module ASP for 2012 to be almost 3X lower than was expected in 2008.
- A similar trend is occurring in 2017—the median estimate of 2017 module ASP made in 2014 was approximately $0.57/W; in the first three months of 2017 the median estimate was $0.37/W.

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Notes: Median, maximum, and minimums may vary because of the differing set of analyst projections for each year.
Sources: 86 separate estimates from 17 institutions.

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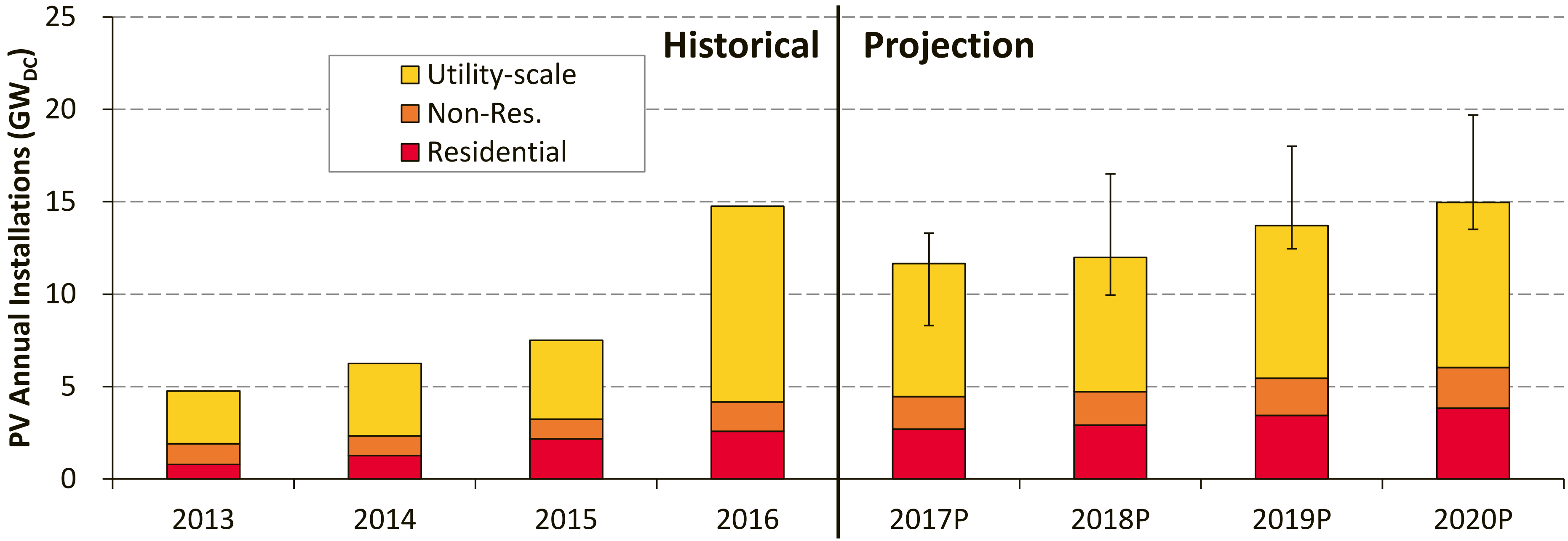
Agenda

- State and Federal Updates
- Global Market Updates
- U.S. Deployment
- U.S. Pricing
- Global Manufacturing
- Component Pricing
- Market Activity

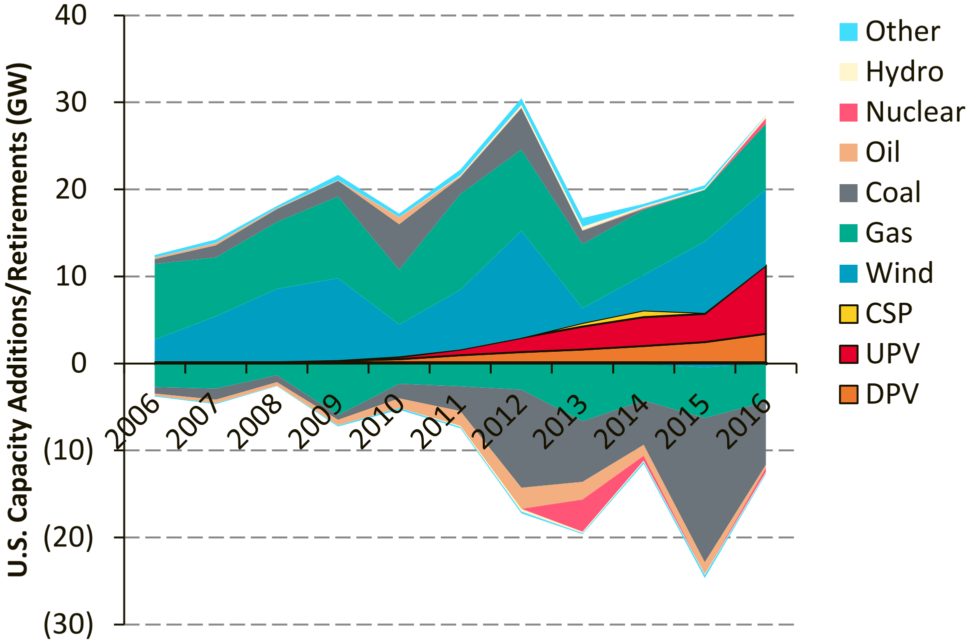
U.S. PV Demand

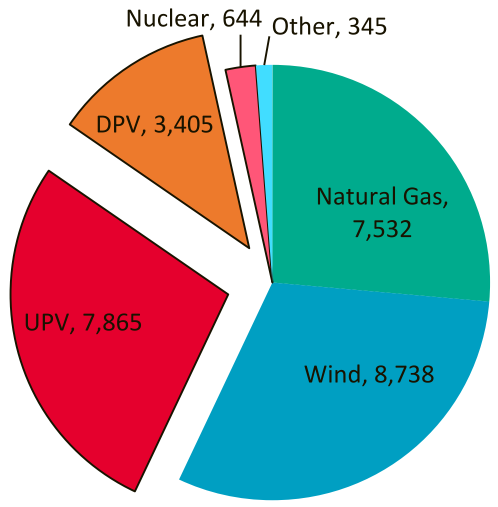


- Analysts estimate U.S. solar installations in 2017 will be between 8.5 GW and 13.5 GW - a drop from the 2016 peak, however, larger than every other previous year.
  - The drop in deployment is expected to come entirely from the utility-scale sector, as the other sectors are expected to grow between 2016 and 2017.
- The median analyst figures project that 50 GW of PV will be installed between 2017 and 2020, more than doubling the current installed capacity of 40 GW.
- Between 2017 and 2020, utility-scale PV installations are projected to remain the largest market sector; however, the distributed market is estimated to grow beyond 6 GW of annual deployment by 2020.

Note: P = projection. Bar represents median projection. Error bars represent high and low projections
Sources: 2013–2016 data from GTM Research & SEIA (U.S. SMI 2016 YIR); 2017-2020 data displayed represents the median figures from the following sources: BNEF (12/20/16); Cowen & Co. (08/23/16); Deutsche Bank (010/15/16); Goldman Sachs (01/02/17); GTM Research & SEIA (March 2017); IHS Technology (3/31/17).

U.S. Generation Capacity Additions by Source





- In 2016, for the first time in U.S. history, solar was the largest source of new electricity generation capacity, with approximately 40% of all new generation capacity.
  - Wind and solar combined for 70% of new generation.
- U.S. has installed ~20 GW of new capacity per year in past decade, while retiring ~17 GW annually in the past five years—the retirements are mostly gas plants, which are being replaced, and coal plants.
  - It would take 50-60 years to change the entire U.S. generation fleet at the current pace of replacement.

Sources: 2004-2010 (except solar): EIA.U.S installed capacity, Form 860. 2011-2013: FERC: "Office of Energy Projects Energy Infrastructure Update for December 2012/2013/2014/2015." 2006-2013 Distribute Solar (DPV), GTM/SEIA, U.S. Solar Market Insight Q4 2014, using PV converted to AC using .8333 derate factor. 2014 DPV, SEPA "2014/2015 Solar Market Snapshot". 2009-2016 Utility PV, and 2015-16 DPV, EIA "Electric Power Monthly" (February 2017).

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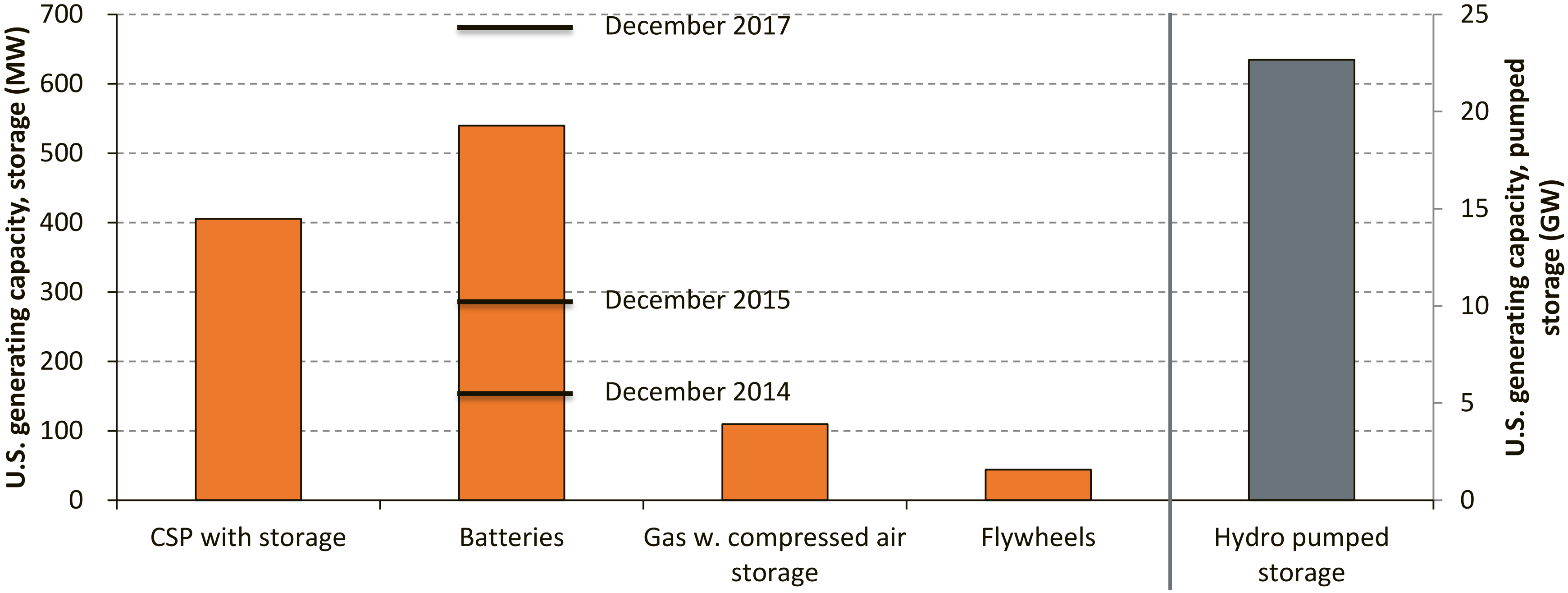
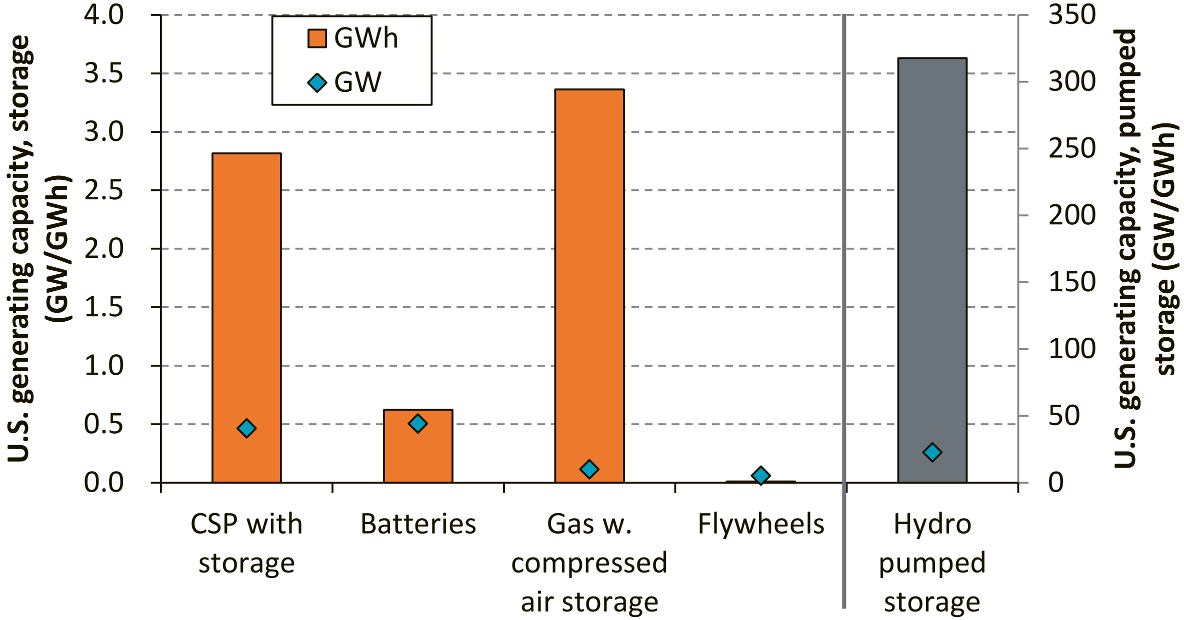
U.S. Electric Storage Capacity, December 2016

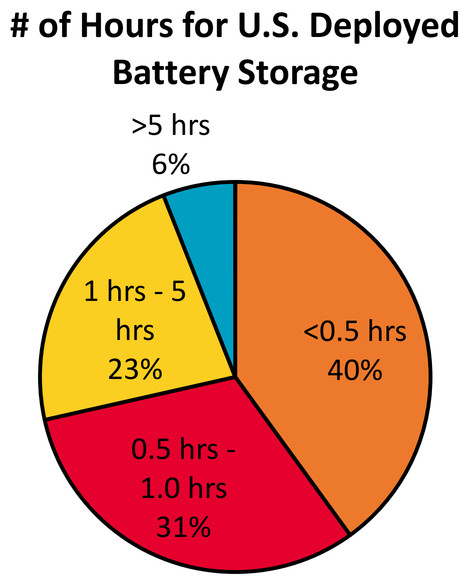


- As of December 2016, CSP had the third-largest storage capacity of any technology in the United States, behind pumped storage (23 GW) and batteries (540 MW).
- U.S. battery storage grew 85% in 2016, and the EIA plans for a further 26% increase in 2017 to 678 MW.
  - 2017 plans may underestimate battery growth as previous year's planned total was 24% of what was actually installed in 2016.

Source: EIA "Electric Power Monthly," Table 6.1. Electric Generating Summer Capacity Changes (MW), November 2016 to December 2016.

U.S. Electric Storage Capacity vs. Duration, April 2017

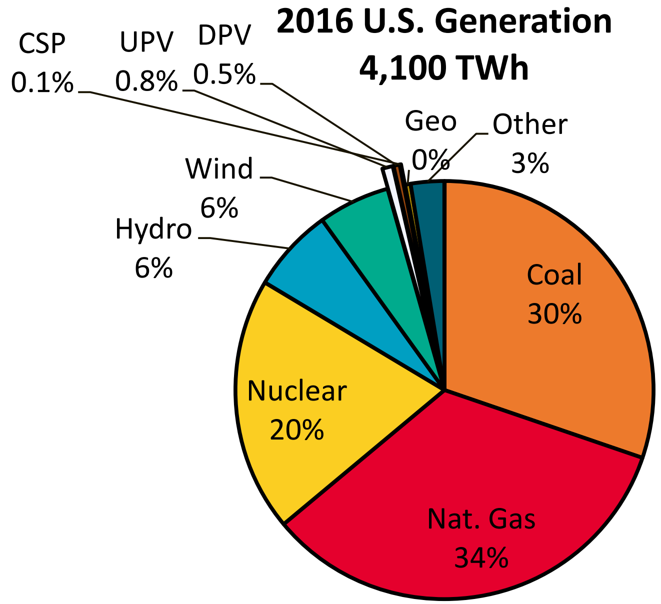


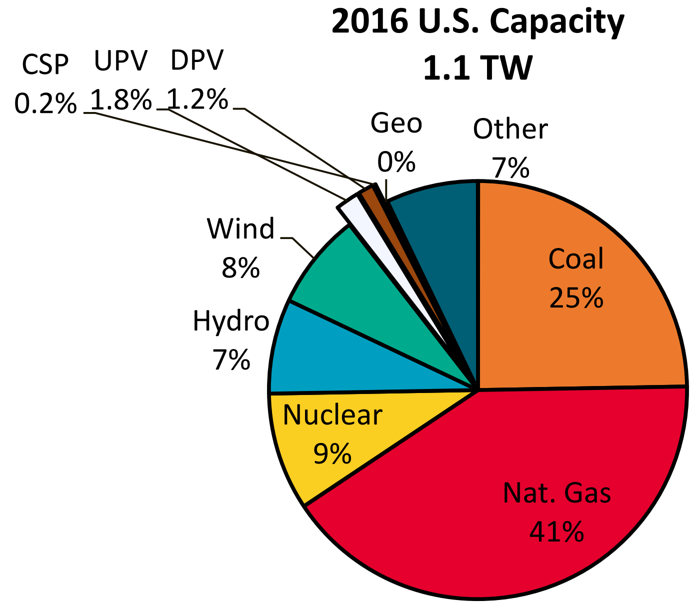


- Despite batteries growing to be the second largest source of storage in the United States they provide fewer hours of storage than other technologies, such as CSP.
  - For example, CSP plants with storage can provide, on average, six hours of energy, versus one hour for batteries.
  - 40% of U.S. deployed battery systems can provide fewer than 30 minutes of storage, while only 6% offer more than 5 hours of storage.
- Short- and long-term storage provide different services to the grid.
  - Short-term storage can smooth variability in generation while long-term storage can replace baseload power.

Source: Department of Energy "Global Energy Storage Database, accessed April 20, 2017. https://www.energystorageexchange.org/

2016 U.S. Capacity and Generation





- Despite solar representing a large amount of new generation, it still represents a relatively small amount of total U.S. capacity and generation.
  - At the end of 2016, solar represented 3.2% of net summer capacity and 1.4% of annual generation.
- 65% of U.S. generation came from fossil fuels in 2016 with another 20% coming from nuclear.
  - Capacity is not proportional to generation as certain technologies (e.g. nat. gas) have lower capacity factors than others (e.g. nuclear).

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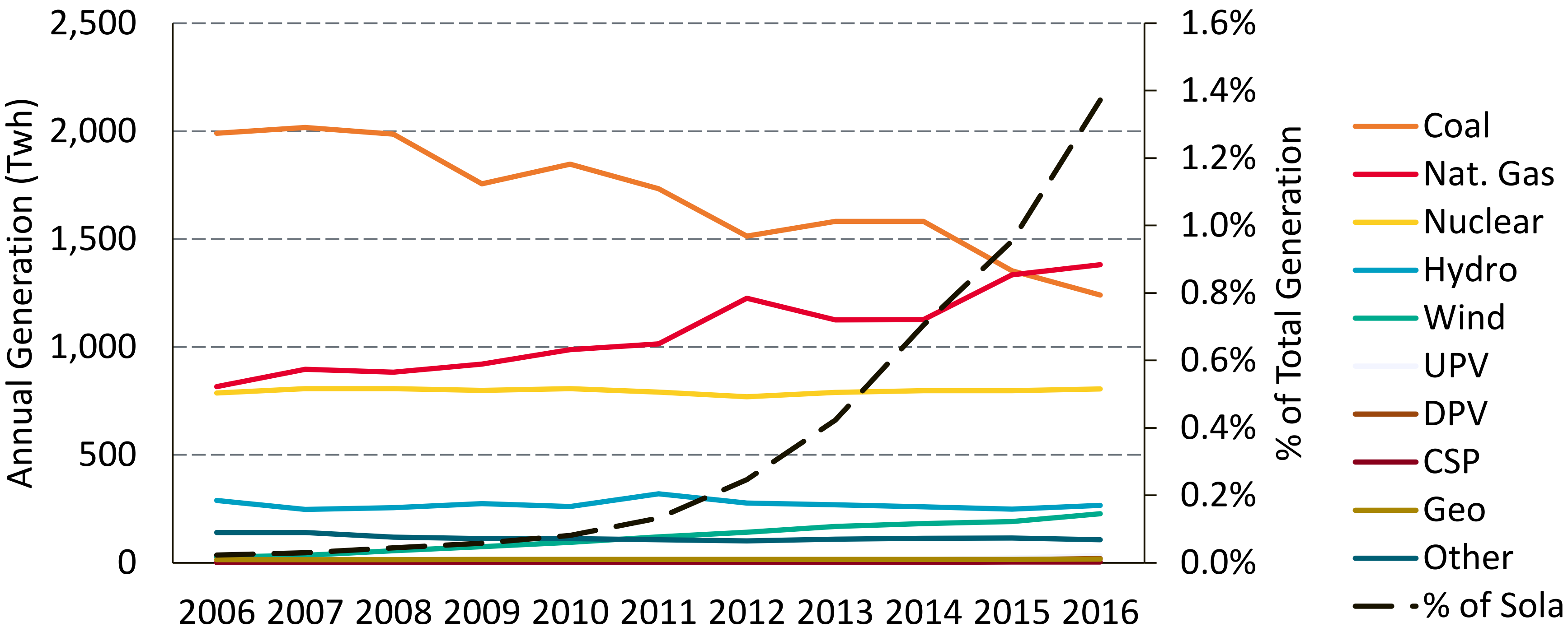
Sources: EIA Electric Power Monthly (February 2017).

U.S. Generation, 2006–2016



- Coal and natural gas generation have been heading in opposite directions.
  - In 2016, natural gas facilities produced more electricity than coal facilities for the first time, compared to 2006 when coal generated approximately 3X natural gas.
- Despite solar only contributing 1.4% of electric generation its percentage has increased 73X since 2006.

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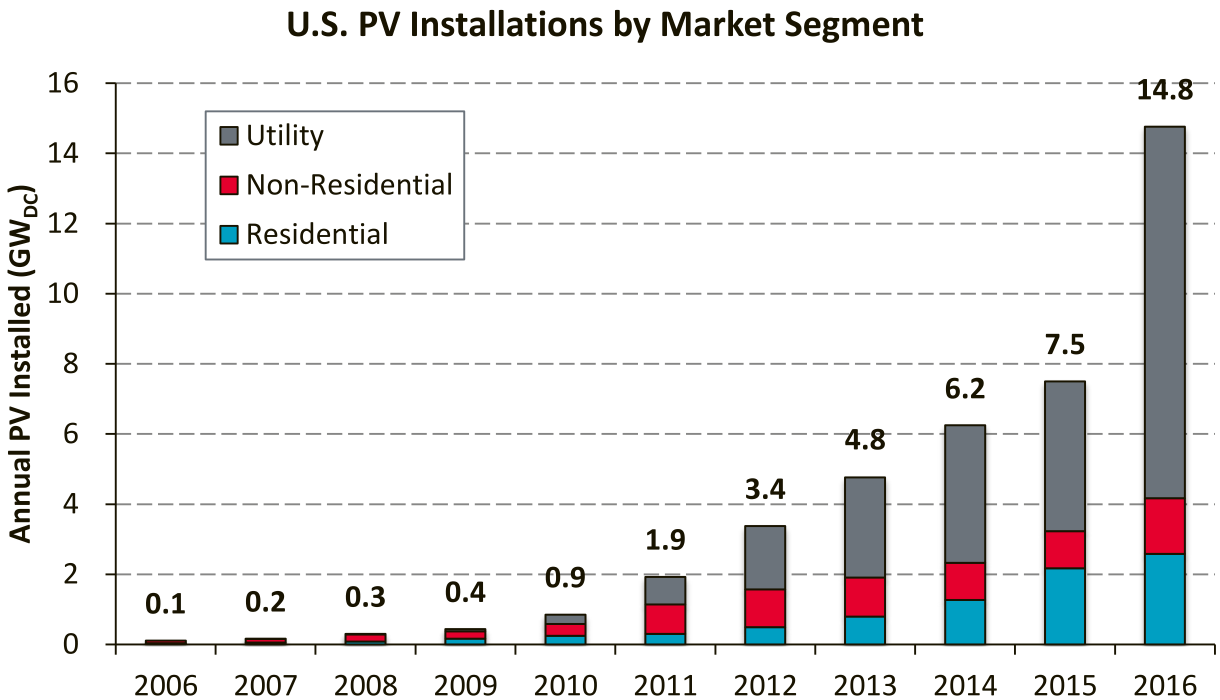
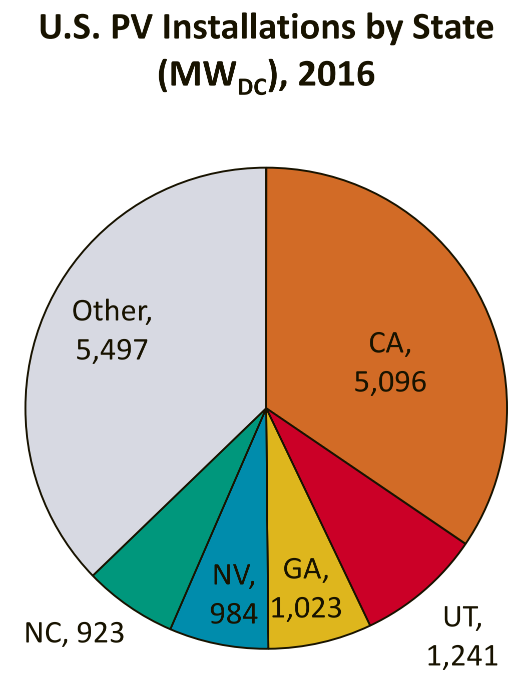
Sources: EIA Electric Power Monthly. Solar DPV values before 2013 are from SEIA & GTM Research, assuming an average production of 1,300 kWh/kW.

U.S. Installation Breakdown





- The United States installed 14.8 GW_{DC} of PV in 2016, 40.4 GW total
  - 2016 PV installations were larger than 2014 and 2015 combined, or all PV installations before 2014 combined
  - Utility-scale PV installations represented 72% of 2016 annual installations; however, the residential and non-residential markets also grew by 19% and 50% respectively, y/y.
- In 2016, the top 5 states represented 63% of the market—22 states installed more than 100 MW, 9 states had more than 1 GW of cumulative PV capacity.

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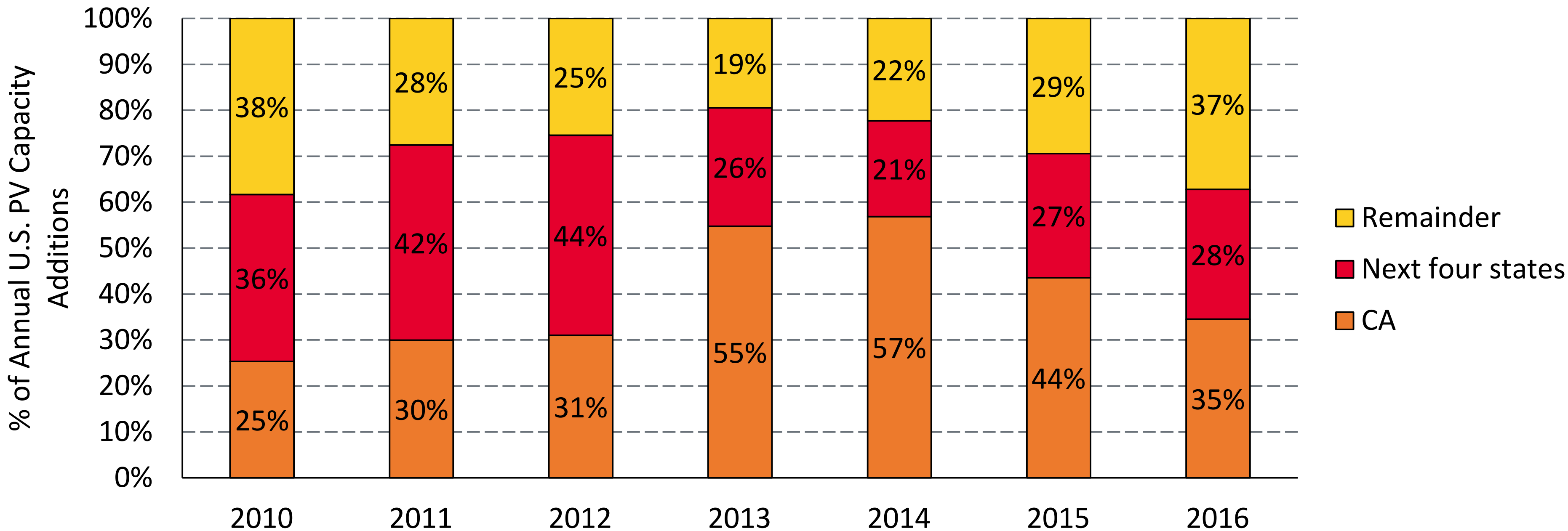
Source: GTM Research/SEIA : U.S. Solar Market Insight 2016 Year in Review.

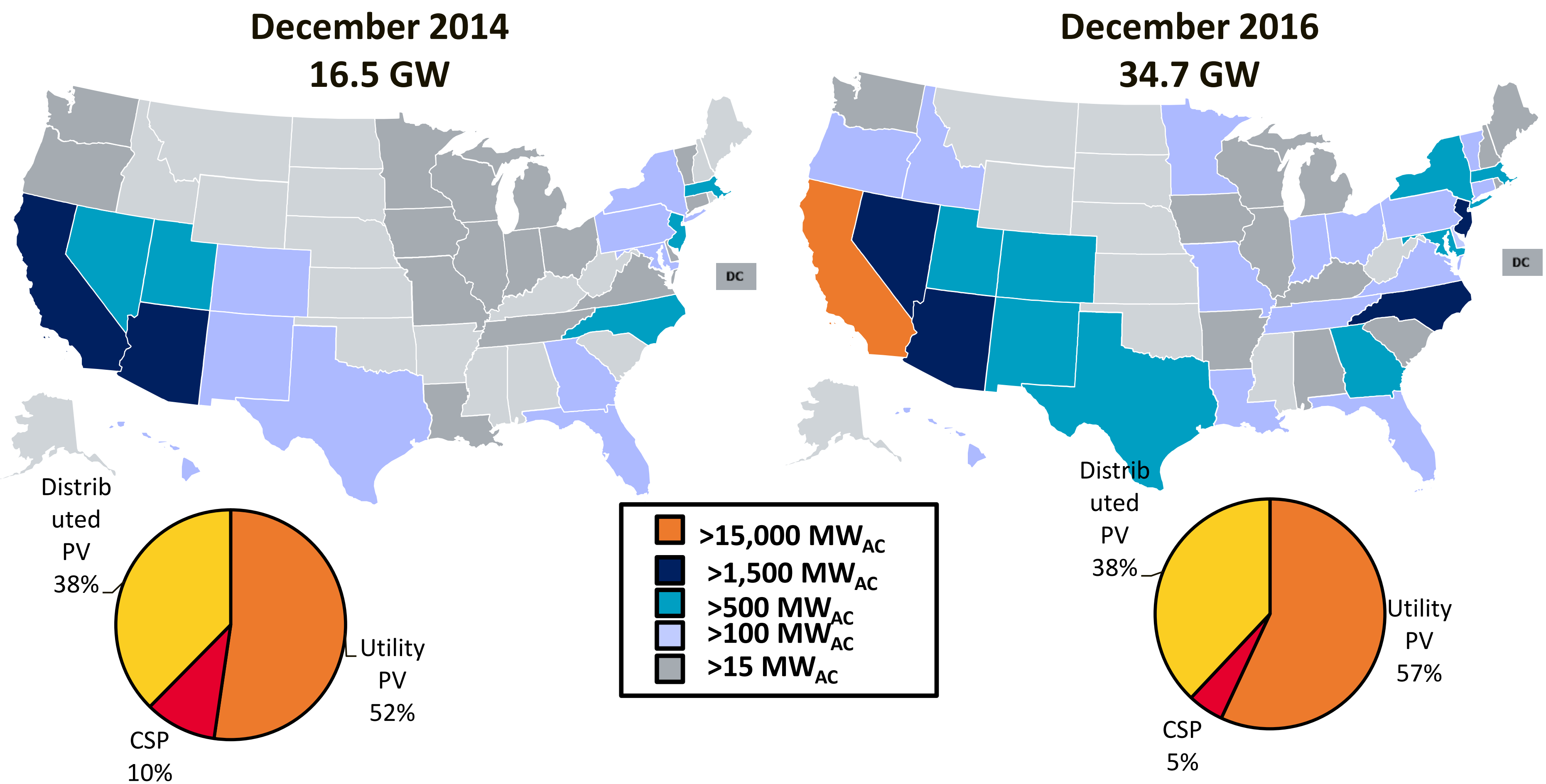
U.S. Installation Breakdown



- While California PV installations grew by 56% from 2015 to 2016, the state contributed much less to total U.S. PV deployment than in the previous three years.
- 63% of all new solar capacity in 2016 was built in five states; however, this is the smallest concentration since 2010 when the United States only installed 850 MW_{DC}.
  - In 2016, five states installed more than the total U.S. did in 2010, and 16 states installed more than the largest 2010 market (California).

Source: GTM Research/SEIA : U.S. Solar Market Insight 2016 Year in Review.

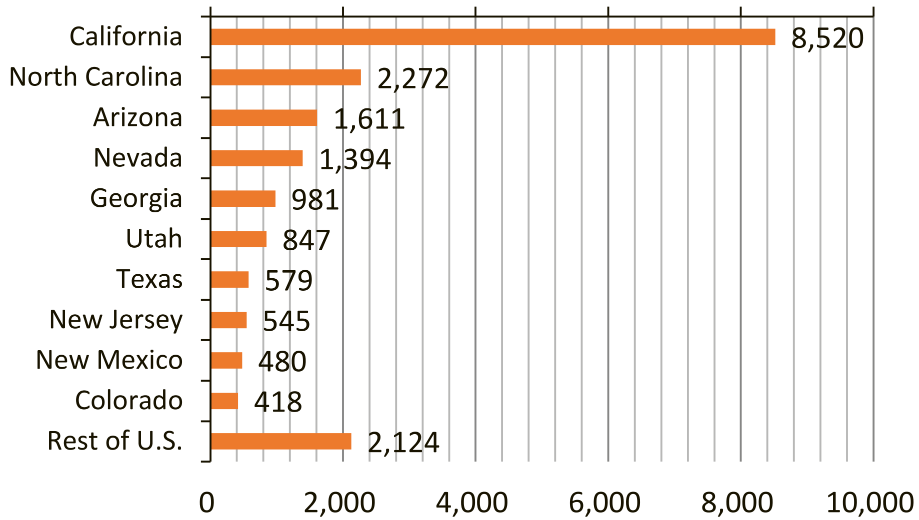
Cumulative Solar Change, 2014–2016

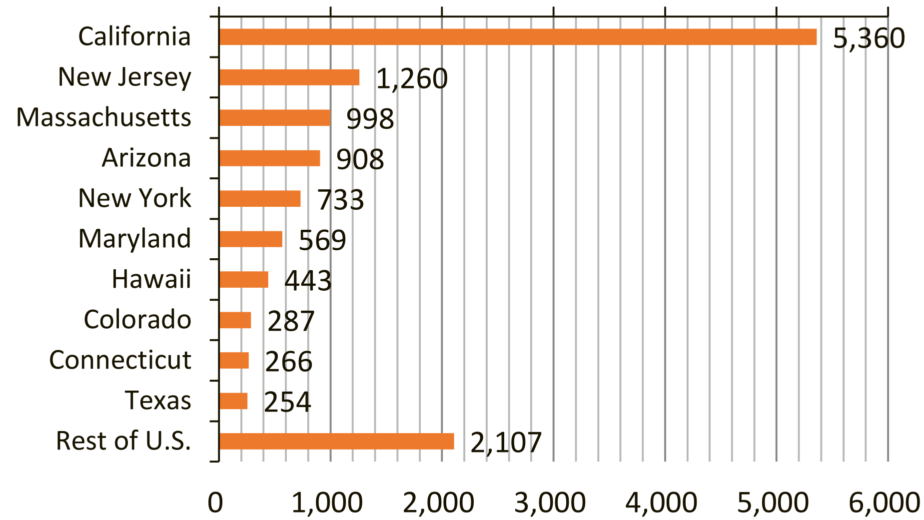


- At the end of 2016, there were more than 100 MW-AC of solar in 28 states (15 states in 2014) and more than 15 MW-AC in 39 states and DC (32 states and DC in 2014).
  - More than half of solar capacity is still in two states.

Source: EIA, Electric Power Monthly (February 2017, February 2015).

U.S. Installation Breakdown





- At the end of December 2016, there were 33.0 GW-AC of solar systems in the United States.
  - Of the 33.0 GW, 19.8 GW were utility-scale PV and 13.2 GW were distributed PV.
- As of December 2016, California system capacity represented 42% of all U.S. PV capacity, leading in both the utility-scale and distributed sectors.
- Half of the top 10 states led in both the utility-scale and distributed sectors, while the other states on the list had less diverse deployment.

Source: EIA, "Electric Power Monthly," forms EIA-023, EIA-826, and EIA-861 (February 2017).
Note: EIA monthly data for 2016 is not final. Additionally, smaller utilities report information to EIA on a yearly basis, and therefore, a certain amount of solar data has not yet been reported.

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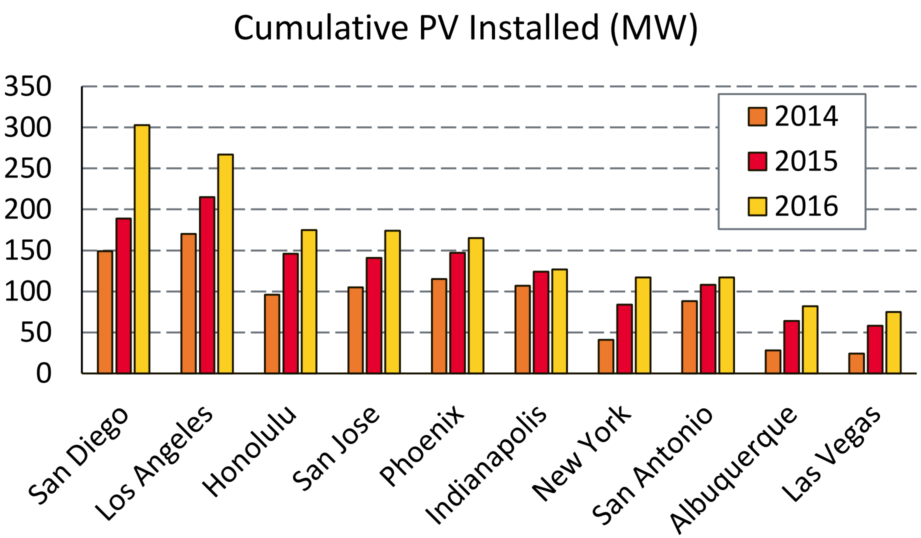
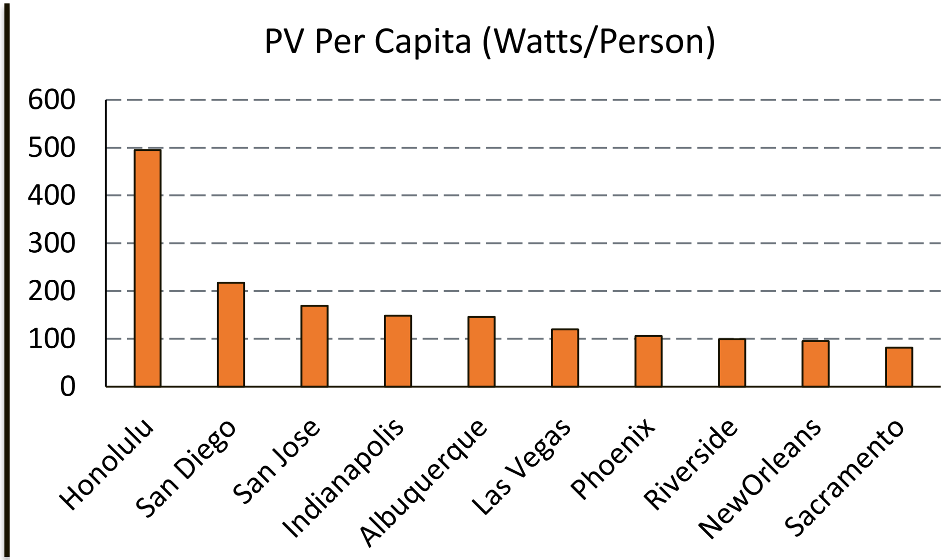
Leading U.S. Cities

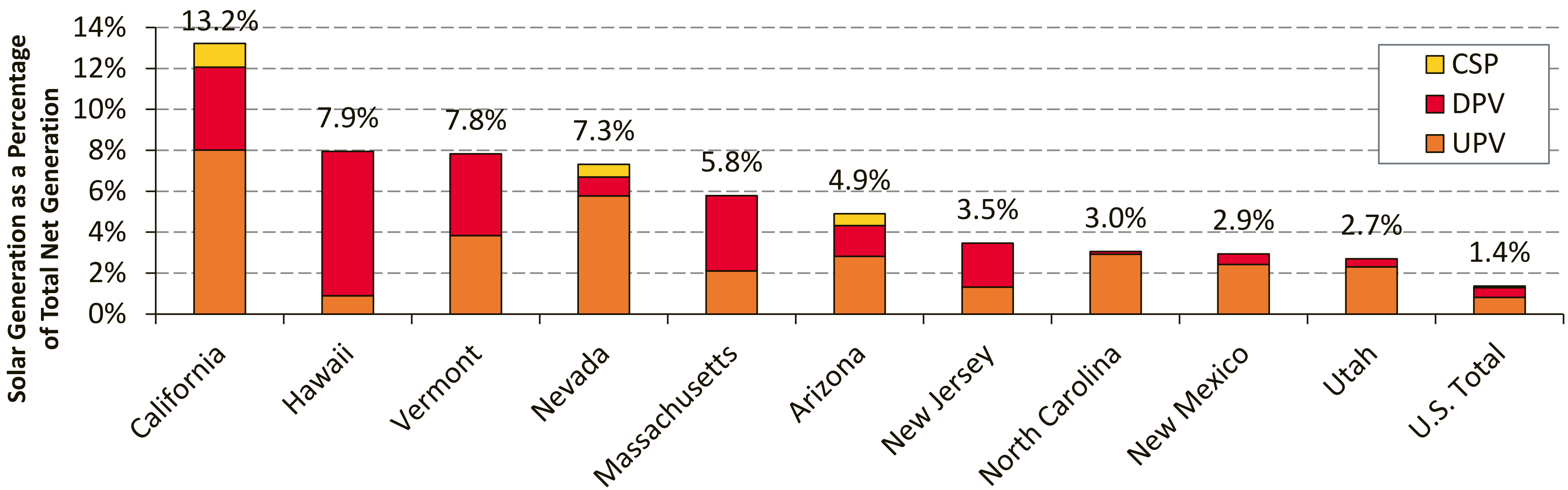




- At the end of 2016, the top 10 cities represented 1.6 GW of cumulative PV capacity, or 4% of total installed U.S. PV capacity.
  – It is estimated that these cities are only using 3%–14% of their technical potential for rooftop installations.
- Seventeen cities had installed more than 50 watts/person at the end of 2016.
  – Honolulu had installed approximately 0.5 kW per person.

Source: "Shining Cities Harnessing the Benefits of Solar Energy in America." Spring 2017.

Solar Generation as a Percentage of Total Generation, 2016



- Five states produced more than 5% of total net generation from solar in 2016, and an additional five states produced more than 2.5% of total net generation from solar.
- Solar technology contribution varied by state, with Hawaii generating most of its energy from distributed PV, while North Carolina generated the vast majority of its energy from utility-scale PV.
  - During the same time period, CSP generated more than 1% of California's electricity and more than 0.5% in Nevada and Arizona.

Source: EIA, "Electric Power Monthly," forms EIA-023, EIA-826, and EIA-861 (February 2017).
Note: EIA monthly data for 2016 is not final. Additionally, smaller utilities report information to EIA on a yearly basis, and therefore, a certain amount of solar data has not yet been reported. "Net Generation" includes DPV generation.

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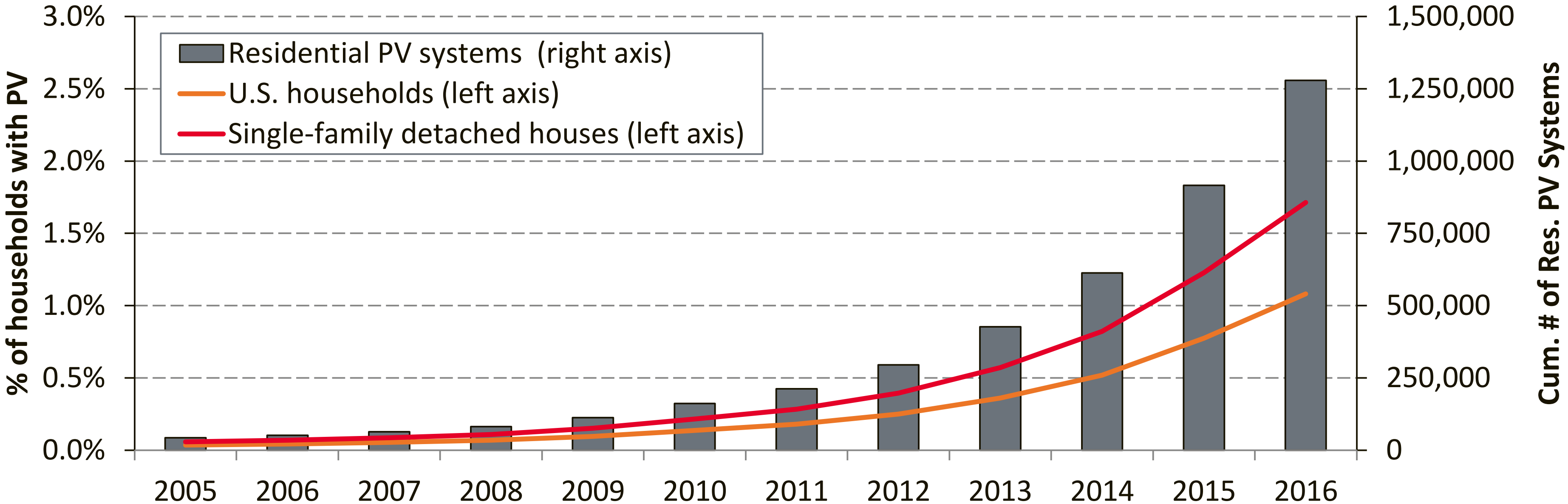
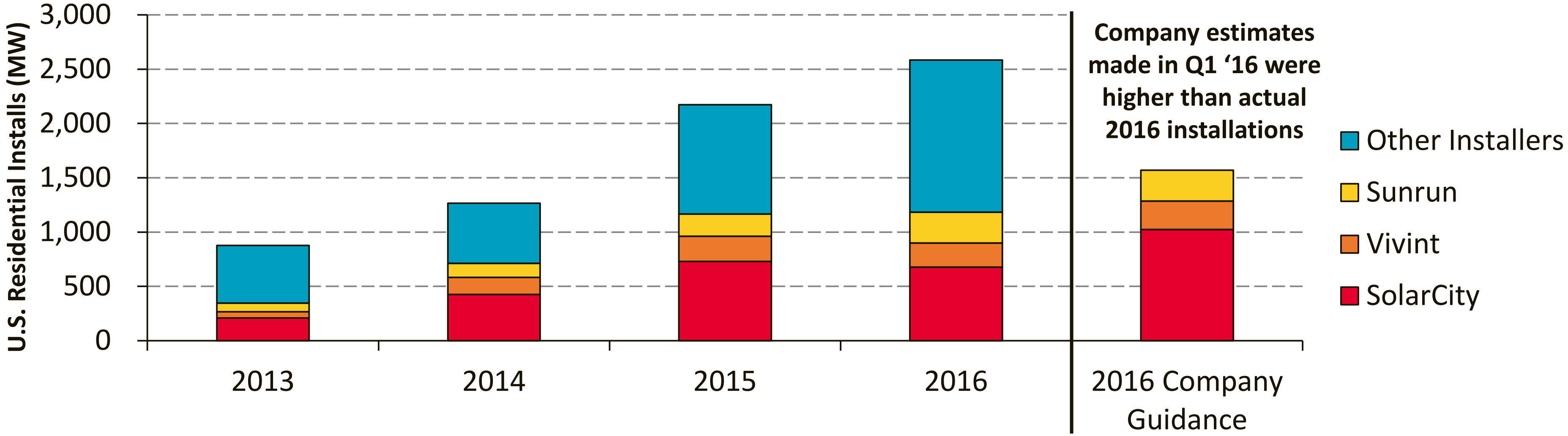
U.S. Residential PV Penetration



- Since 2005, when the investment tax credit was passed by congress, the residential PV market has grown by approximately 51% per year, or about 95X.
- At the end of 2016, there were over 1.25 million residential PV systems in the United States.
  - The millionth U.S. residential PV system was likely installed in Q2 2016.
- Still, only 1.1% of households own or lease a PV system (or about 1.7% of households living in single-family detached structures).
  - However, solar penetration varies by location. Hawaii, California, and Arizona have residential systems on an estimated 29%, 9%, and 7% of households living in single-family detached structures.

Sources. Res. PV Installations: 2000-2009, IREC 2010 Solar Market Trends Report; 2010-2015, SEIA/GTM Solar Market Insight 2010-16 Year-in-Review. U.S. Households U.S. Census Bureau, 2015 American Housing Survey; state percentages based on 2000 survey.

SolarCity, Vivint Solar, and Sunrun Residential Market Share

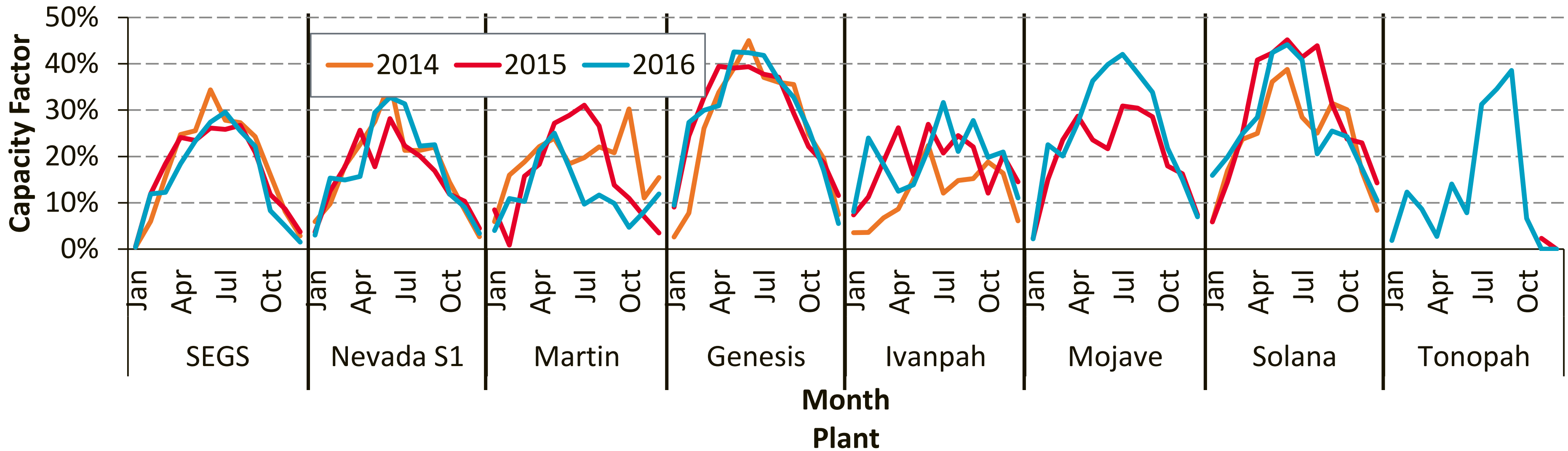


- Residential Solar installations have historically been dominated by a few installers.
- Flat sales by Vivint Solar and SolarCity/Tesla in 2016 stood in contrast to overall market expansion.
  - SolarCity (-34%) and Vivint (-15%) significantly underperformed their own guidance for 2016 deployment, which were made in Q1 2016.
  - With the acquisition of SolarCity by Tesla, the company has emphasized "cash preservation over growth" and has shifted from leasing to selling systems.
- SolarCity/Tesla and Sunrun are also expanding product offerings through PV+storage.
  - Tesla announced 98 MWh of energy storage deployed in Q4 2016.
  - Sunrun announced 20 MWh of orders received for energy PV+storage. "Storage and other advanced technologies add greater value than solar alone and are best addressed with monthly billing models from a dedicated service provider [Sunrun]."

Source: Corporate Filing, GTM/SEIA SMI 2016 Year-in-review.

Note: SolarCity Q4 2016 residential deployment and 2016 guidance are assumed to have the same percentage of total deployment that occurred in Q3 2016.

Capacity Factor of CSP Projects



- In 2016, U.S. CSP plants produced roughly the same energy as in previous years, given the DNI variability each month and year, with three exceptions:
  - Mojave produced 41% more energy from May to September 2016 than it did during the same period in 2015.
  - Tonopah began producing energy in November 2015 though stopped producing in October 2016 through the end of the year due to a molten-salt leak.
  - Martin produced 25% and 36% less in 2016 than in 2015 and 2014 respectively.

Source: System AC nameplate capacity is sourced from EIA Form 860. Monthly system electricity production is sourced from EIA Form 923.

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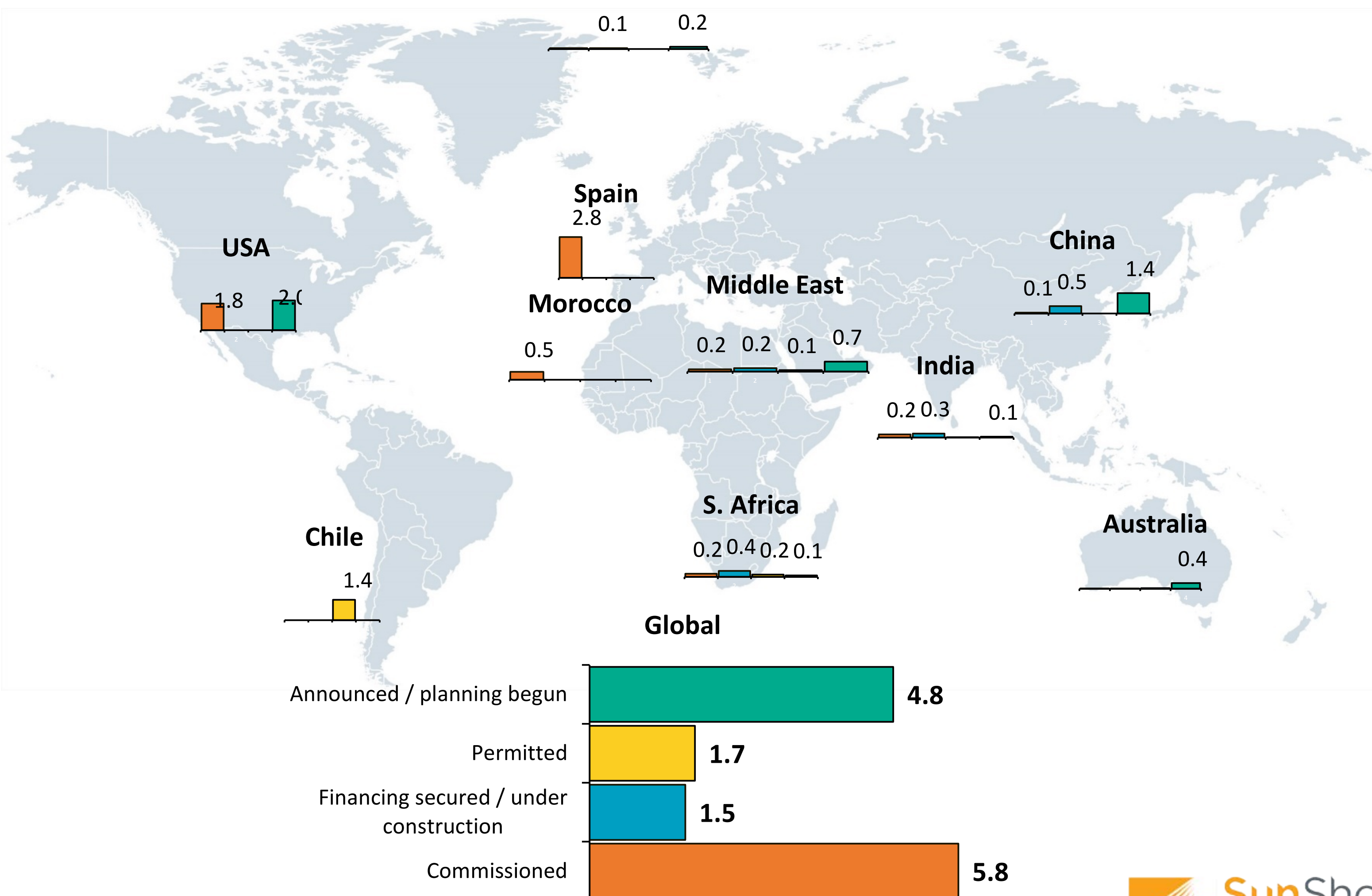
CSP Market Worldwide



Source: Bloomberg NEF "Power Plant" database, accessed 03/22/17. U.S. figures adjusted to include the announced 2 GW Nevada project by SolarReserve.

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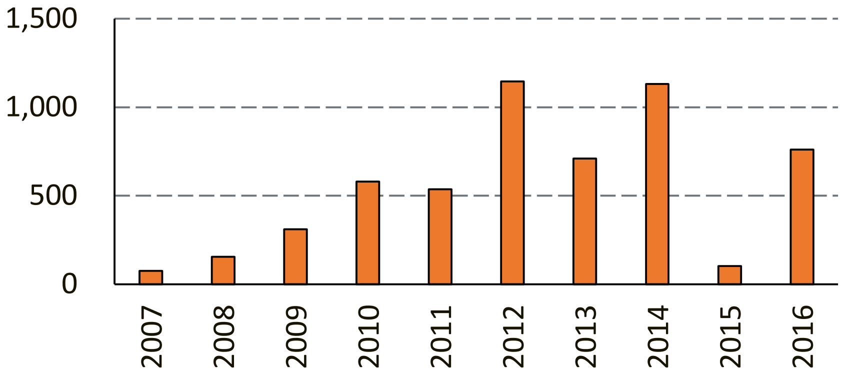
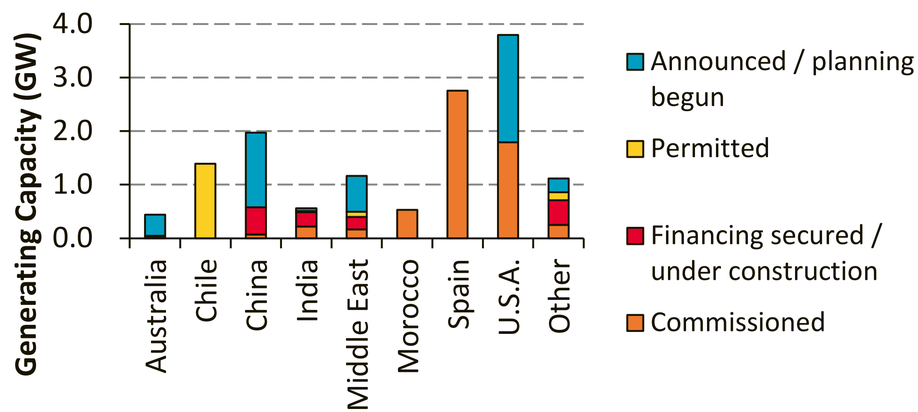
CSP Market Development





- A little more than 750 MW of CSP was installed globally in 2016.
- Between 0.5 GW—1.5 GW of annual CSP installations has occurred globally six of the past seven years.
  - The sustained demand is due to large quantities of CSP deployment in different countries over the years.
- China and Chile are the next two countries to push strong levels of CSP deployment. If the projects in their pipeline are completed they could have comparable markets to Spain and the United States.
  - China could grow even larger as it has set a solar thermal target of 5 GW by 2020 (but has thus far missed its CSP targets).
- The United States also has a very large pipeline; however, it is made up of one 2 GW project by SolarReserve in Nevada—the project differs from many other global projects in development in that it has no electricity offtaker.
- Continued development around the globe has allowed the technology to continue to drop in price
  - In Chile, SolarReserve bid its Copiapó project with a capacity of 240 MW and 14 hours of thermal energy storage, at a record-low CSP price of $63/MWh (in part, due to capacity payments it could receive, highlighting the *value* of CSP).
  - SolarReserve announced that its 2 GW Nevada project, "will be lower cost than natural gas power plants, but just as reliable during peak periods."

Sources: Bloomberg NEF "Power Plant" database, accessed 03/22/17; CSP Today (09/07/16); Reuters (09/14/16); Utilitydive (10/17/16)

Global Presence of U.S.-based CSP Companies

- U.S.-based company Glasspoint uses CSP technology for enhanced oil recovery. It currently has a 1-GW thermal capacity project in Oman scheduled for completion in 2017.
- BrightSource, a U.S.- and Israeli-based company, has two major projects using tower and heliostat CSP technologies—the 392-MW Ivanpah plant in California, and the 121-MW Ashalim project under construction in Israel. BrightSource, along with the U.S.-based CSP manufacturer SkyFuel, are also providing technology for 199 MW of projects being developed in China.
- The U.S.-based developer SolarReserve, which focuses on tower and heliostat plants using molten-salt technology, currently has one commissioned plant—the 125 MW Tonopah plant in Nevada. They also are pursuing prospects in South Africa, Chile, and a 2 GW project in the United States, which have thus far not received financing or a PPA.

Sources: Bloomberg NEF "Solar Thermal Market Outlook." January 20, 2017.

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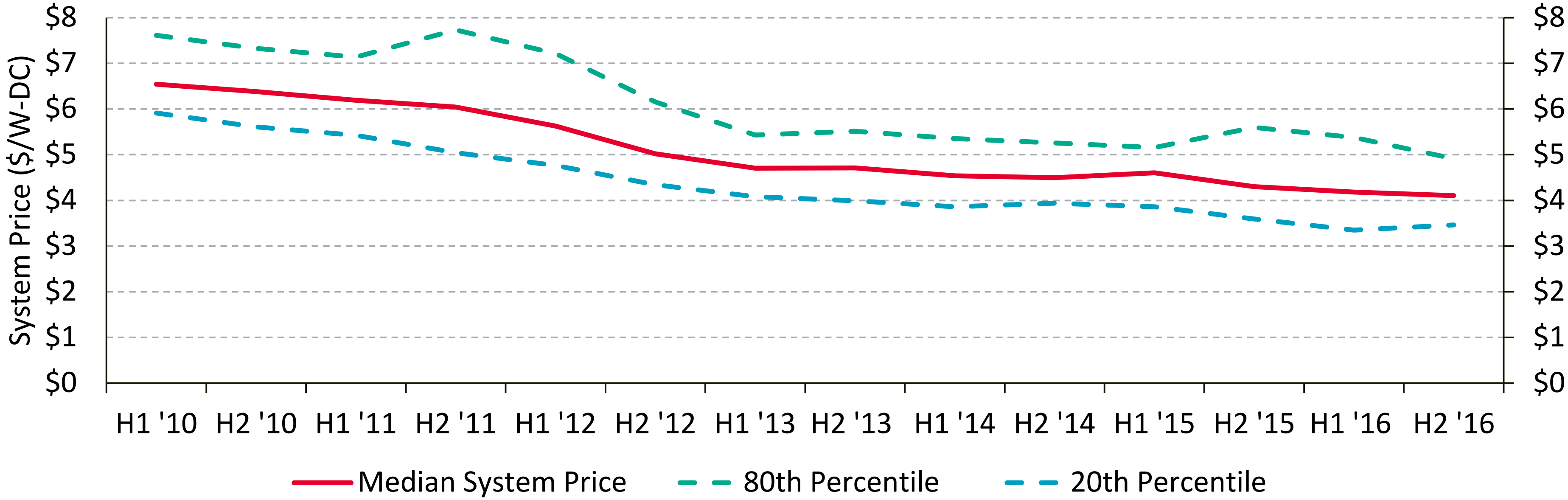
System Pricing from Select States

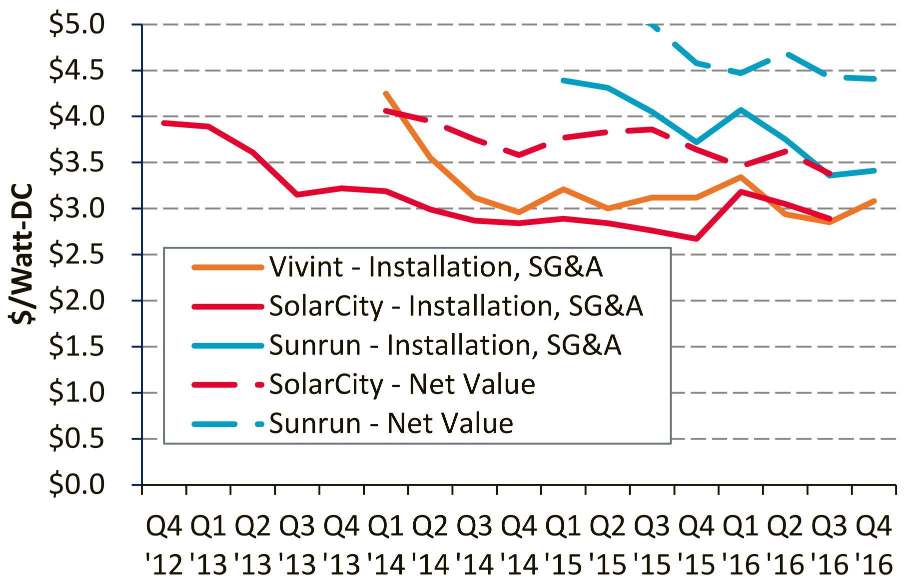
2.5 kW–10 kW

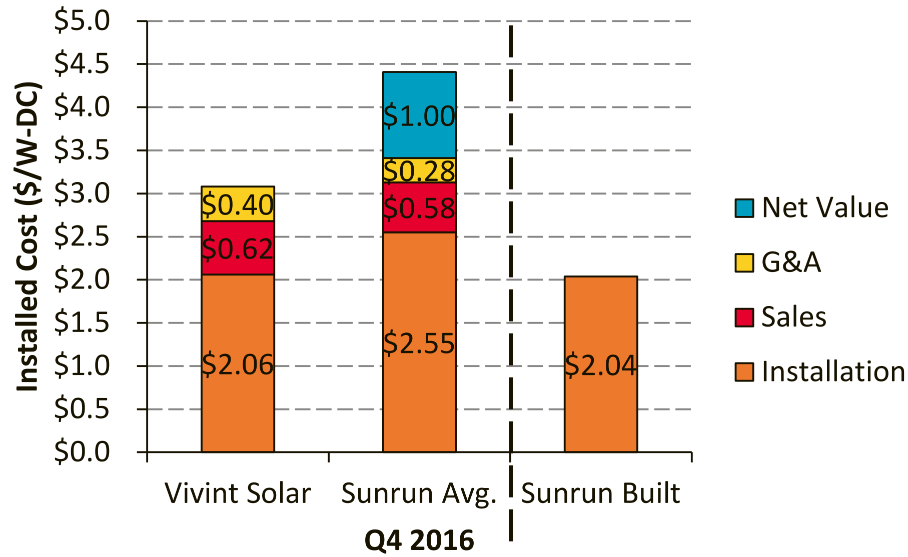


- In 2016, the median reported system prices fell 4%, and the price range contracted.
- System prices fell, on average, 1.7% between H1 2016 and H2 2016.
- Lowest prices (20th percentile) were seen in Arizona ($2.96/W), while higher prices (80th percentile) were seen in Maryland ($5.04/W) in H2 2016.

2016 MW: AZ (82); CA (387); MA HO (79); MA 3-P (35); MD (2); NY H.O (37); NY 3rd-P (59).
Note: MA does not report whether a system is third-party owned. Therefore, it was estimated using the "applicant entity" or "installer" for the following organizations: SolarCity, CPF Capital, Sunrun, Vivint, and Sungevity.
Sources: CA NEM database; MA SREC program; Arizona Public Services and Salt River Project; MD Energy Administration; NY PV Incentive Program. All programs accessed 4/4/17

SolarCity, Vivint Solar, and Sunrun Cost & Value





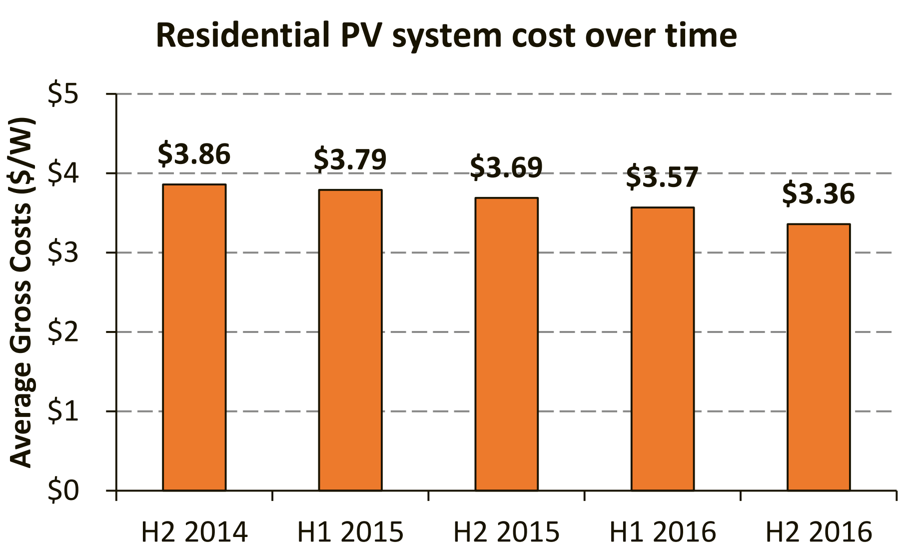
- From Q4 ‘15 to Q4 ’16, Vivint Solar and Sunrun systems total costs decreased 1% and 8% respectively.
  - Installation costs for both companies decreased 12% y/y; however, overhead costs have been burdened by lower than expected total installs.
- Sunrun reported a profit (or net value) of $1/W in Q4 2016; however, $0.60/W of that comes from assumed contract renewals.
- With Tesla’s acquisition of SolarCity there is less transparency of their costs.

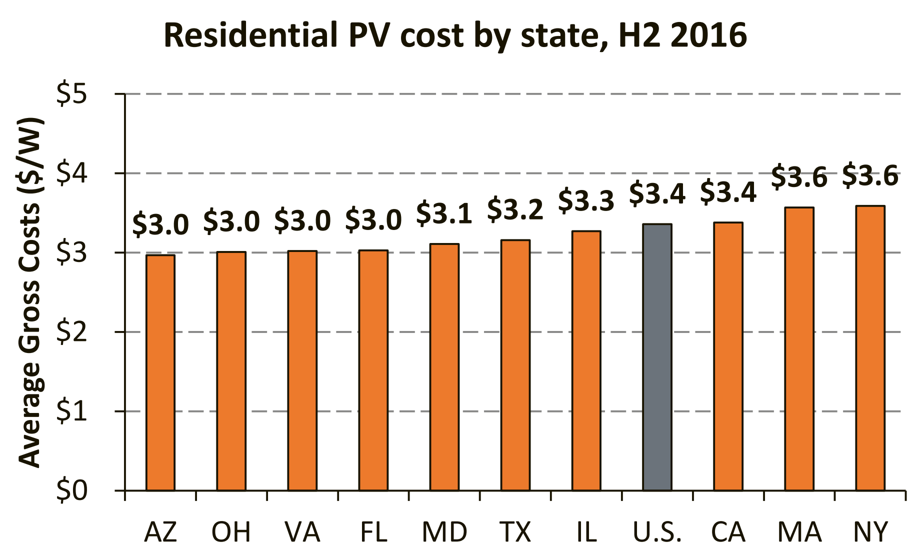
energy.gov/sunshot

Sources: Corporate Filings.

System Costs Reported by EnergySage

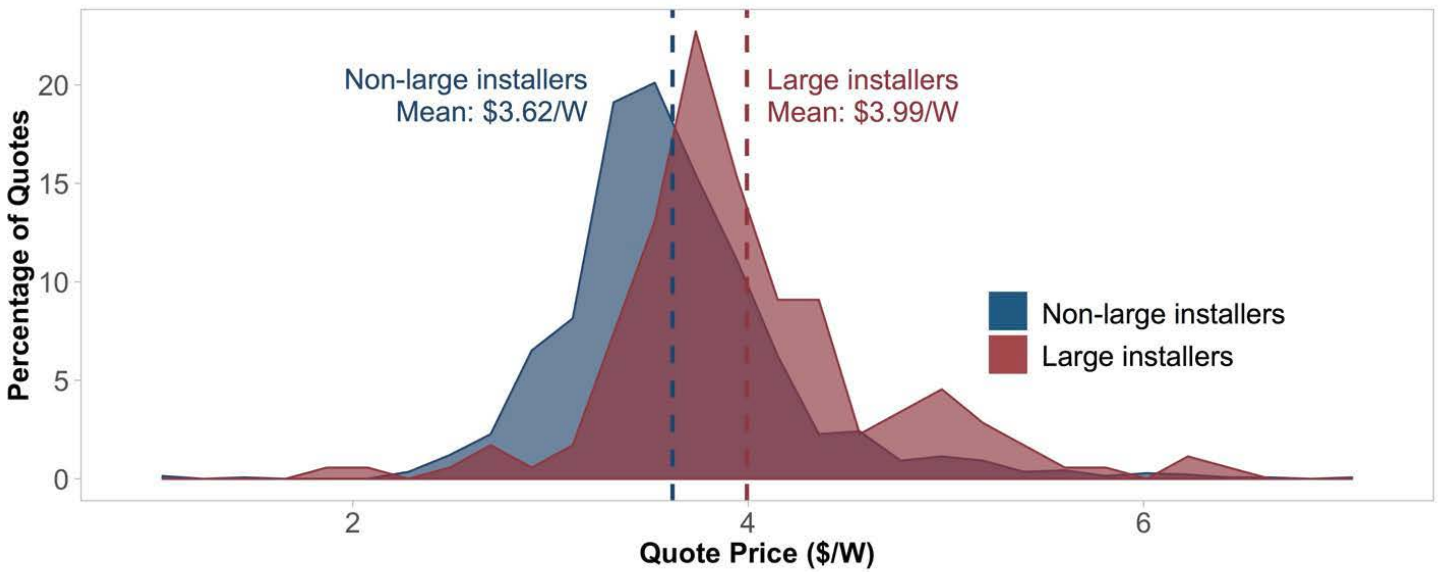
- From H2 2015 to H2 2016, EnergySage reported a 9% reduction in the average gross costs of a residential system.
  - The standard deviation of PV system quotes in H2 2016 was $0.48/W.
  - EnergySage quotes also reported an average system payback period of 7-8 years.
- Residential system quotes varied by state. In H2 2016, the average gross cost of a residential system in New York was 21% higher than the average gross cost of a residential system in Arizona.





Sources: EnergySage "Solar Market place Intel Report H1 2016 – H2 2016"

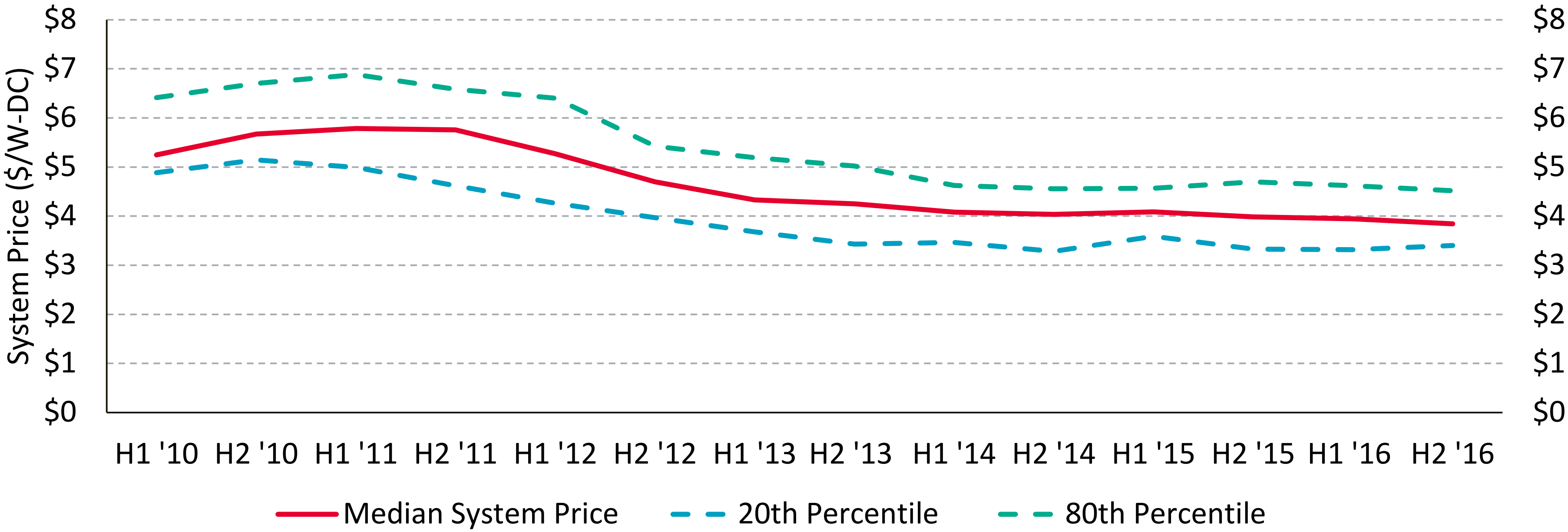
NREL Study Find Pricing Differences Between Large and Small Installers



- A recent NREL study matched over 1,500 price quotes for residential PV systems from 2014 to 2016 and found that quotes from large installers were $0.33 higher than non-large installers (10%).
  - Large installers tended to quote smaller systems with a greater use of micro-inverters; adjusting for these factors NREL still found a $0.21/W difference in price.
  - The study also found that the range of price quotes from small installers tended to be narrower than that of larger installers ($1.61/W span between the 10th and 90th percentile quotes for larger installers; $1.25/W for small installers).
- The results of the report suggests, "that some residential PV customers may forego lower prices for the opportunity to work with a large installer [e.g., known-brand, better warranty, and inverter replacement terms] but also that customers could benefit from obtaining more quotes before deciding to install a system."

Source: Eric O'Shaughnessy and Robert Margolis. "Using Residential Solar PV Quote Data to Analyze the Relationship between Installer Pricing and Firm Size." NREL. April 2017.

System Pricing from Select States
10 kW–100 kW



- Reported host-owned system prices for systems 10 kW–100 kW fell 3% between H1 and H2 2016.
  - Third-party systems also fell by 7% during that timeframe.
  - Third-party systems are being *reported*, on average, $1/W–$2/W more expensive than host-owned systems. Third-party owners may use different methodologies to determine a price.
- Lowest prices (20th percentile) were seen in Arizona ($2.82/W), while highest (80th percentile) were seen in Massachusetts ($5.04/W) for third-party-owned systems.

2016 MW: AZ (54); CA (126); MA HO (47); MA 3-P (17); MD (3); NY H.O (36); NY 3rd-P (32).

Note: MA does not report whether a system is third-party owned. Therefore, it was estimated using the "applicant entity" or "installer" for the following organizations: SolarCity, CPF Capital, Sunrun, Vivint, and Sungevity.

Sources: CA NEM database; MA SREC Program; Arizona Public Services and Salt River Project; MD Energy Administration; NY PV Incentive Program. All programs accessed 4/4/17.

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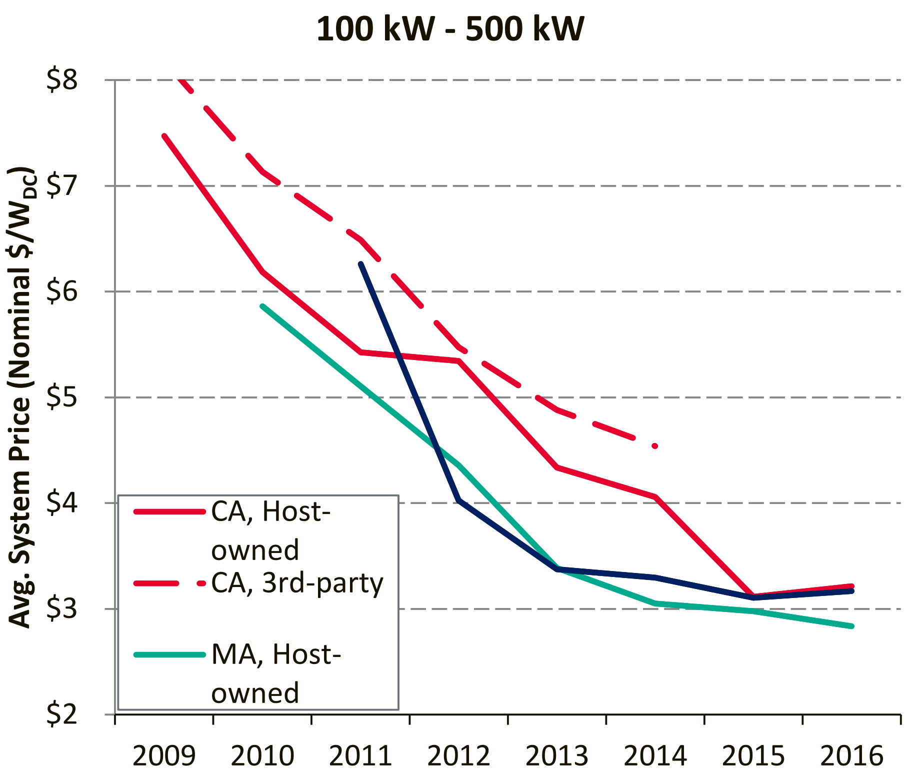
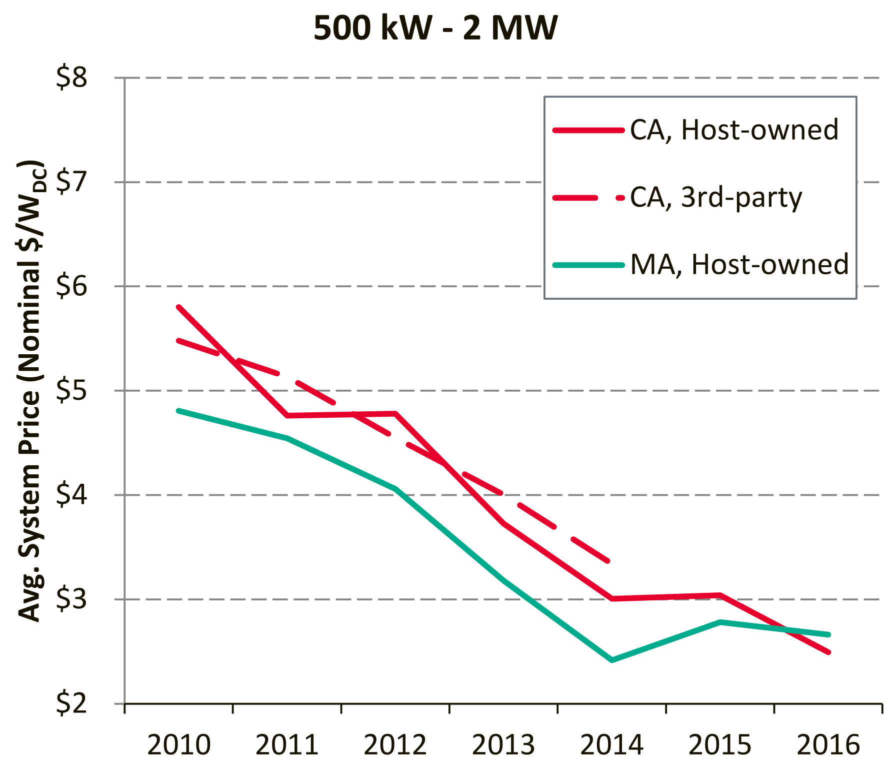
Average System Pricing by Size and State

100 kW–500 kW and 500 kW–2 MW





- Systems sized 100 KW – 500 KW see flat pricing on average with slight increases in New York and California.
- Prices for systems 500 KW – 2 MW fell 11% between 2015 and 2016, largely driven by dramatic drop in price in California.

2016 MW: (100–500 kW): CA H.O. (98); MA H.O.(29); NY (26). (500 kW–2 MW): CA H.O. (70); MA H.O.(87).

Sources: CA NEM database; MA SREC program; NY PV incentive program. All programs accessed 4/4/17.

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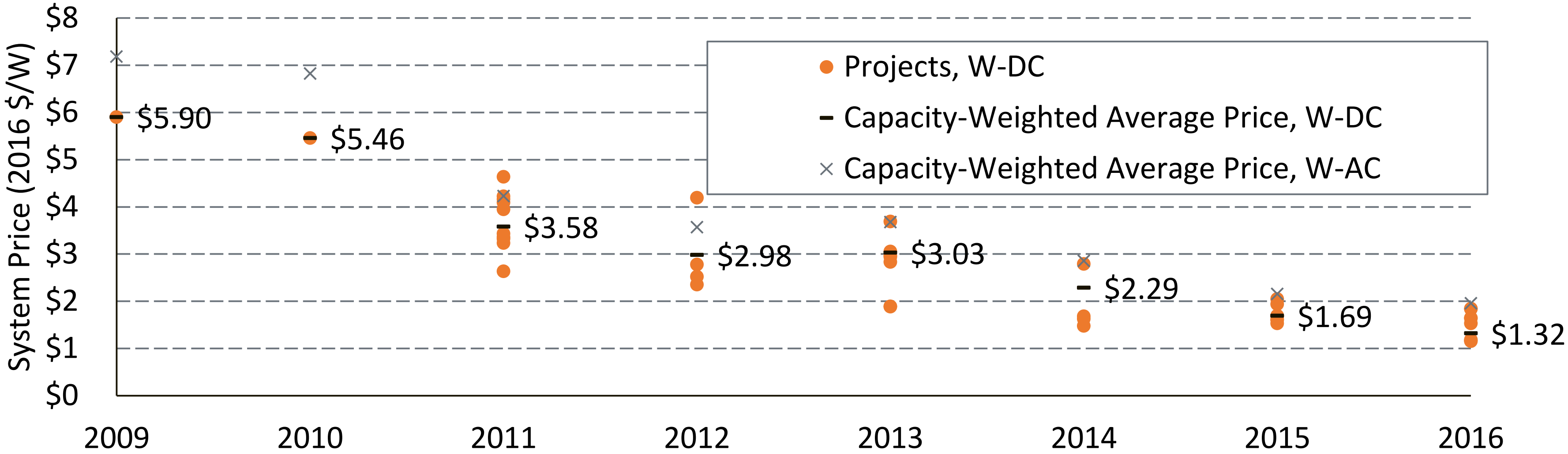
Utility-owned PV Pricing (>5 MW)



- In the above system price data set for nine regulated utilities the capacity weighted average price of a utility-owned PV system fell 78% to $1.32/W_{DC}$ ($1.95/W_{AC}$) between 2009 and 2016.
  - The capacity weighted average system price fell 22% from 2015 to 2016
- From 2015 to 2016 PV system prices in Watts-AC fell slower than they did in Watts-DC because of an increase in inverter loading ratio, from roughly 1.3 to 1.5.
  - With cheaper modules, it is may be more economical to add more modules per inverter.
- The majority of utility-scale systems are owned by IPPs, which have PPAs with utilities. PPA pricing, while not in lock-step with system pricing, generally followed the same trends.
  - From 2010 to 2016 the generation-weighted average PPA price for utility-scale systems placed in service in that year fell 64%; from 2015 to 2016 PPA prices dropped 33% for systems placed in service in that year.
  - Systems should have much lower PPA pricing in the near future. as the average price for a PPA signed in 2015 was around $40/MWh, or 30% lower than PPAs for systems installed in 2016.

Note: data sample consists of 42 projects with 1.2 GW–DC of capacity

Sources: FERC Form 1 Filings from the following utilities: Arizona Public Service; Florida Power & Light; Duke Energy Progressive; Georgia Power; Indiana Michigan Power Company; Kentucky Utilities; Pacific Gas & Electric; Public Service of New Mexico; Southern California Edison. PPA pricing from “Utility-Scale Solar 2015” (Bolinger and Seel 2016).

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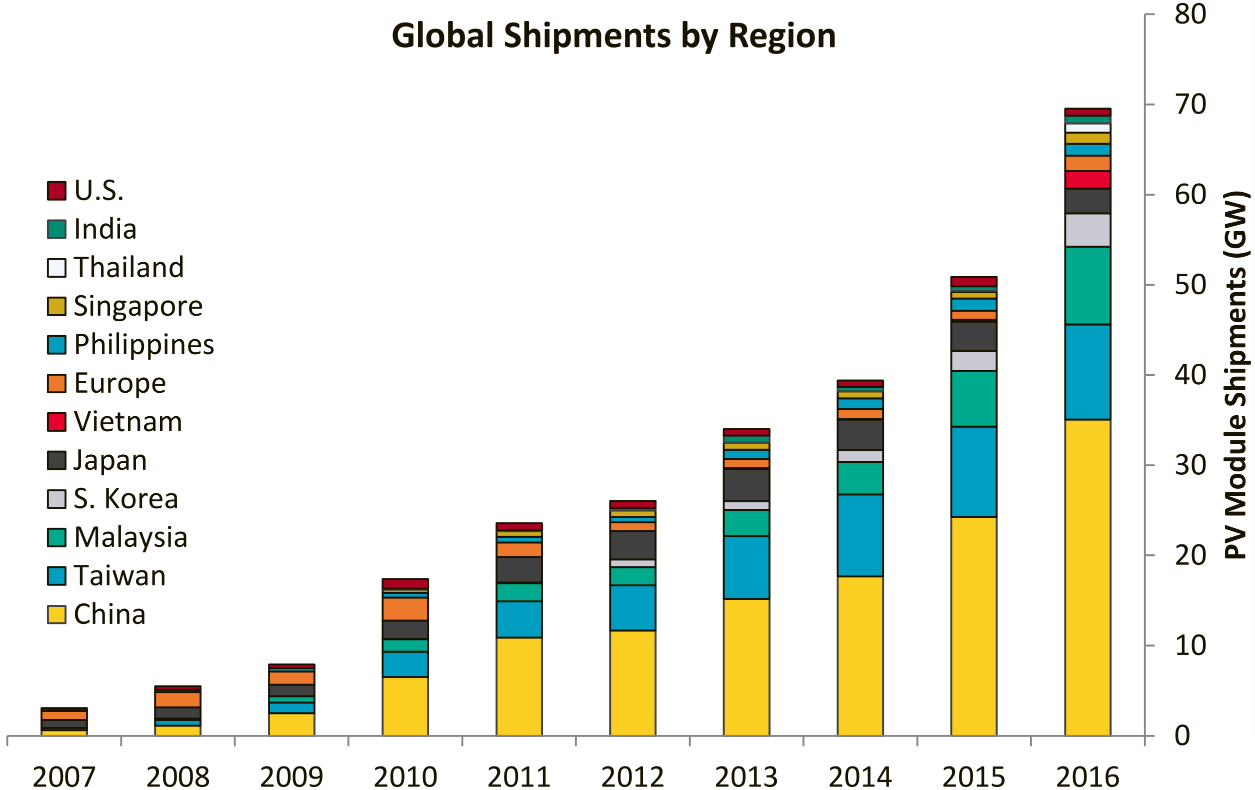
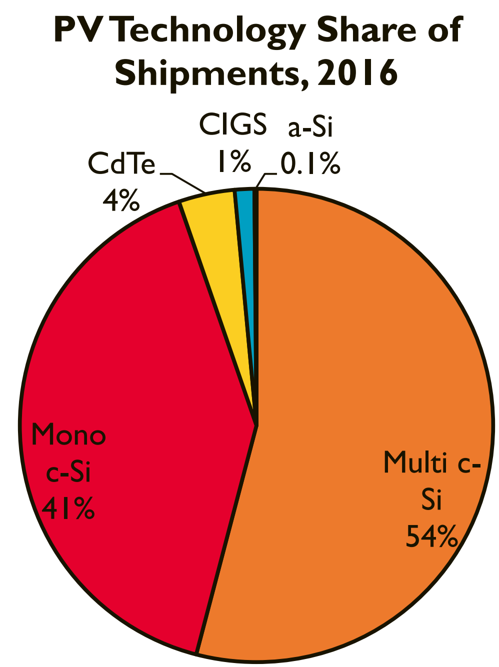
Global Annual PV Shipments by Region*



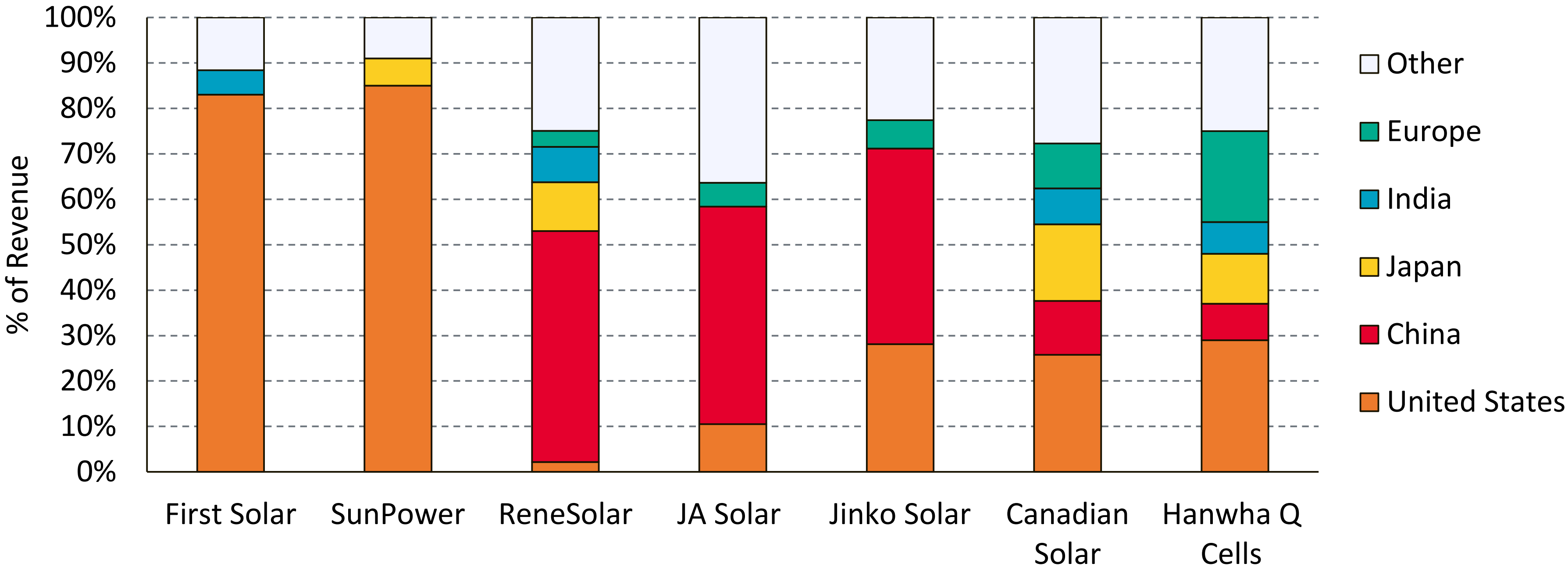


- In 2016, global shipments increased 37% y/y and 22X in the past 10 years.
  - China & Taiwan manufactured 66% of shipments in 2016; Asia countries manufactured ~96%.
  - Ten countries shipped over 1 GW of PV in 2016.
- 95% of shipments in 2016 came from crystalline technology, 4% CdTe (First Solar, etc.), 1% CIGS (Solar Frontier, etc.).

***Note:** Excludes inventory sales and outsourcing.

Source: 2007-2016: Paula Mints. "Photovoltaic Manufacturer Capacity, Shipments, Price & Revenues 2016/2017." SPV Market Research. Report SPV-Supply7. April 2017.

PV Mfgs. % of Sales Revenue by Region, 2016



- PV manufacturers have varying degrees of regional exposure.
  - The majority of revenue from First Solar and SunPower came from the United States with virtually no penetration in the Chinese market.
  - Many of the publicly traded Chinese companies have large revenues from their domestic market, but are less dependent on their home market than U.S. firms.

Note: not all companies separate revenue into each geographic location represented in graphic. In those instances, all non-separated numbers are classified in "other" unless otherwise stated. Canadian Solar and Hanwha Q Cells have not filed their annual reports yet so 2015 numbers are reflected. U.S. numbers for Jinko Solar represent revenues the company received from all of "America" as U.S. was not broken out separately. Renesola's figures are as a weighted averaged of reported quarterly figures.
Sources: Company figures based on Q4 '16 (and previous) SEC filings by the respective companies.

Global Leading PV Manufacturers, by Shipments

2016 2015 2010 2005

Rank	Manufacturer (2016)	Shipments (GW)	Manufacturer (2015)	Shipments (GW)	Manufacturer (2010)	Shipments (GW)	Manufacturer (2005)	Shipments (GW)
1	**Trina**	**5.0**	Trina	3.6	Suntech	1.6	Sharp	0.375
2	**JA Solar**	**4.9**	JA Solar	3.6	JA Solar	1.5	Kyocera	0.142
3	**Hanwha**	**4.0**	Hanwha	3.4	First Solar	1.4	Q-Cells	0.131
4	**Jinko Solar**	**3.9**	Canadian Solar	2.7	Yingli	1.1	Schott Solar	0.095
5	**Motech**	**2.9**	First Solar	2.5	Q-Cells	1.0	BP Solar	0.086
6	**First Solar**	**2.7**	JinkoSolar	2.4	Sharp	0.9	Mitsubishi	0.085
7	**Longi Lerri**	**2.7**	Yingli	2.4	Trina	0.9	Sanyo	0.084
8	**Canadian Solar**	**2.4**	**Motech**	2.1	**Motech**	0.9	Shell Solar	0.055
9	**Yingli**	**2.4**	Neosolar	2.1	Gintech	0.8	**Motech**	0.045
10	**Shunfeng-Suntech**	**2.2**	Shunfeng-Suntech	2.0	Kyocera	0.6	Isofoton	0.039
Other		**36.4**		26.8		6.8		0.270
Total		**69.5**		50.9		17.4		1.410

Sources: Paula Mints. "Photovoltaic Manufacturer Capacity, Shipments, Price & Revenues 2016/2017." SPV Market Research. Report SPV-Supply7. April 2017. "Photovoltaic Manufacturer Capacity, Shipments, Price & Revenues 2015/2016." SPV Market Research. Report SPV-Supply3. April 2016. Navigant "Photovoltaic manufacturer Shipments, Capacity & Competitive Analysis" (April 2009).

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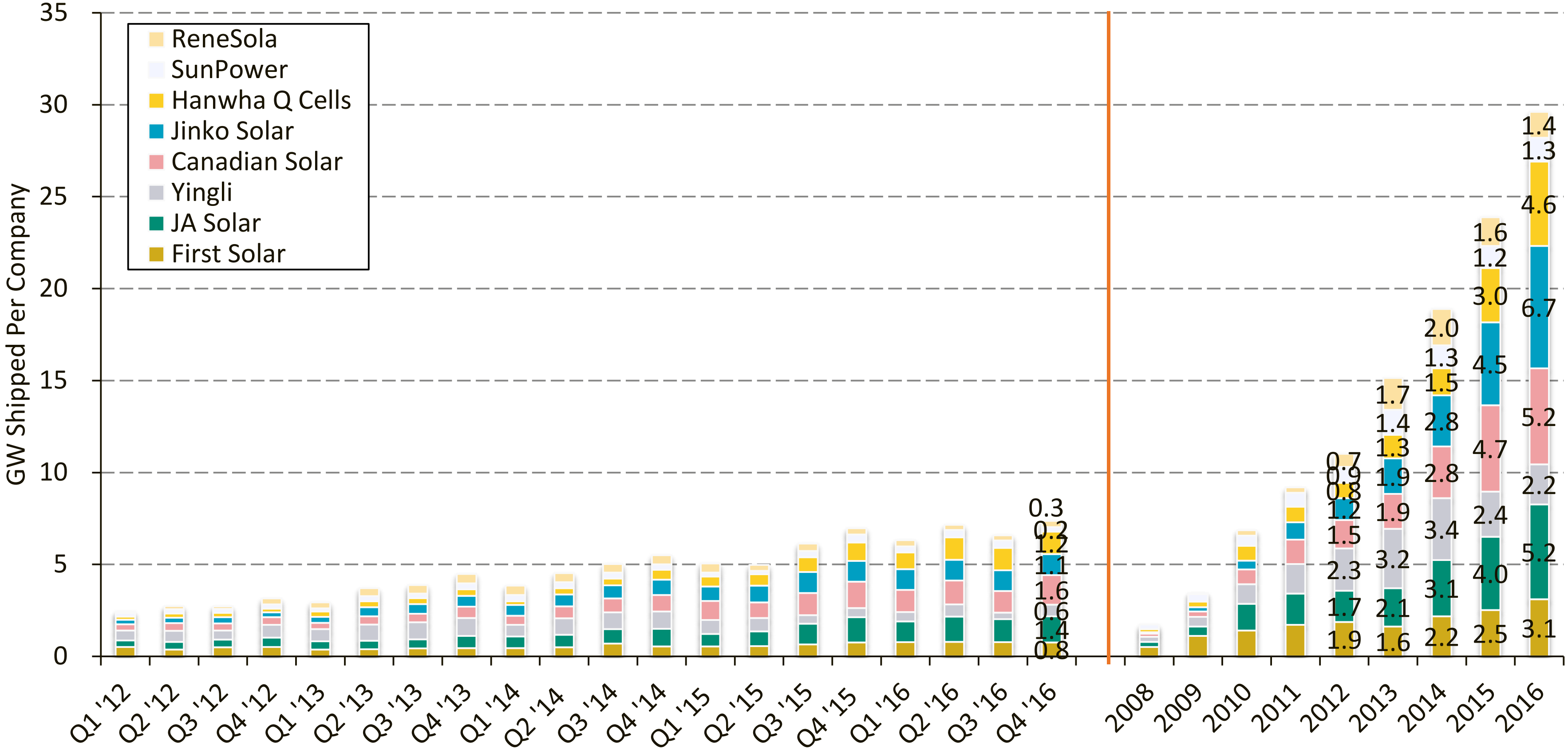
Manufacturers' Shipments

Publically Traded Cell/Module Manufacturers

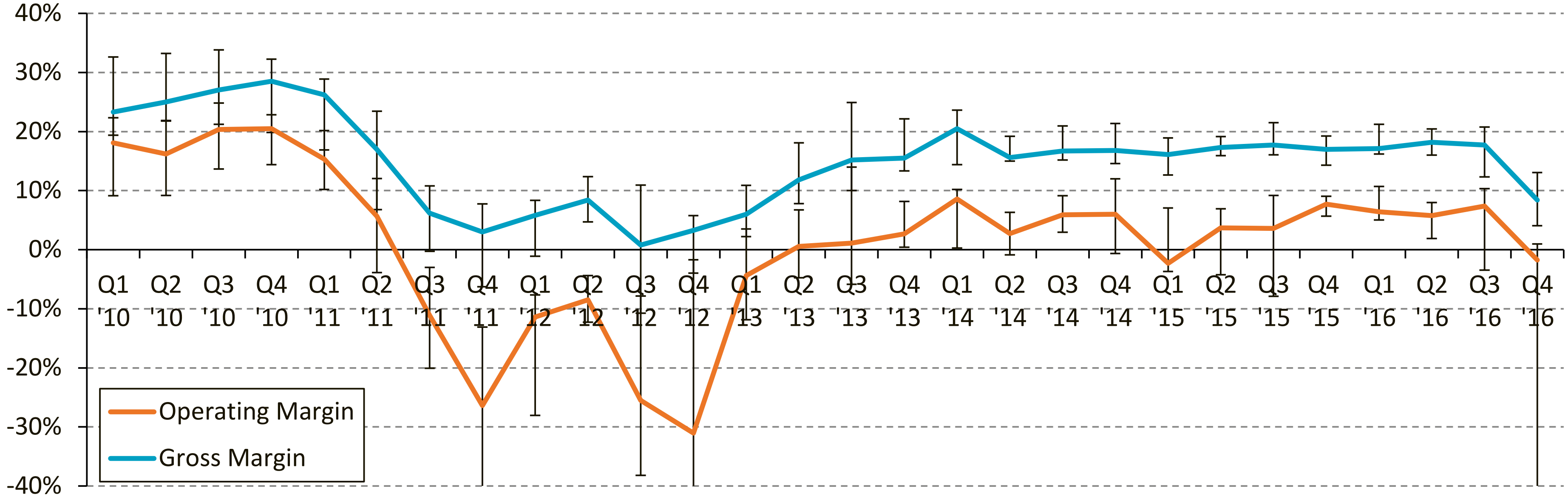


- In 2016, the above leading companies shipped 29 GW, 20% more than in 2015.
  - In Q4 '16, the above companies recorded 7.3 GW of shipments, a 9.5% increase over Q3 '16.
  - Jinko reported the largest shipments to lead with 6.7 GW shipped in 2016.

Note: First Solar reports production, not shipments. Only ReneSola modules represented. For 2016, Hanwha Q Cell's quarterly shipments based on total year reporting.

Sources: Company figures based on Q4 '16 (and previous) SEC filings by the respective companies.

PV Manufacturers' Margins



**Line represents the median, with error bars representing 80th and 20th percentiles for the following companies: Canadian Solar, First Solar, Hanwha Q Cells, JA Solar, Jinko Solar, ReneSola, SunPower, Trina Solar, and Yingli Solar.*

- Industry margins declined from Q3–Q4 2016, with some variation among individual companies.
  - The median gross margins was 8% and the median operating margin was -2% for the above companies in Q4 2016.
- Jinko saw the strongest gross margins in the industry (14%) and the most shipments; SunPower had the lowest gross margin of the surveyed companies at -3% in Q4 2016 and the fewest shipments.
  - Most Asian manufacturers saw gross margins of 7%–13% in Q4 2016.
  - First Solar saw a dramatic drop in margin due to the one time restructuring of assets related to Series 5/Series 6 module development.
- All manufacturers saw drops in margins from Q3 2016 –Q4 2016, consistent with reports of declining module costs.

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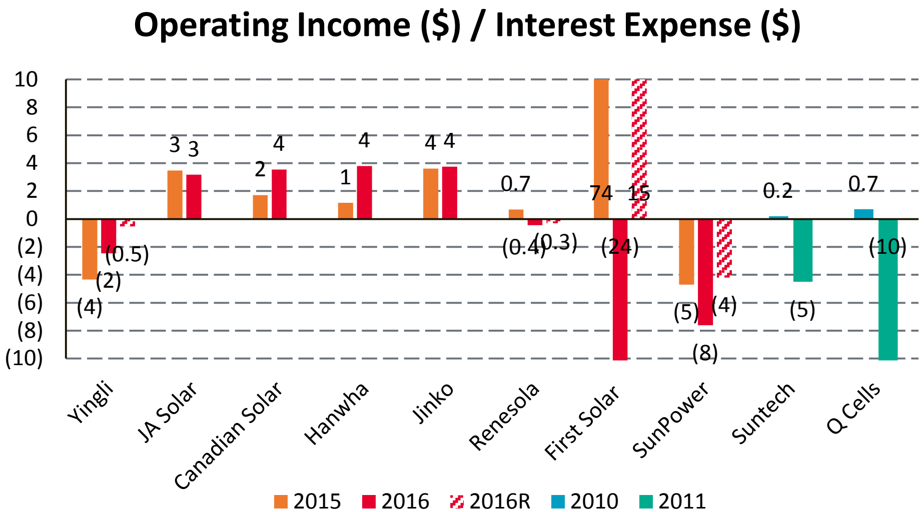
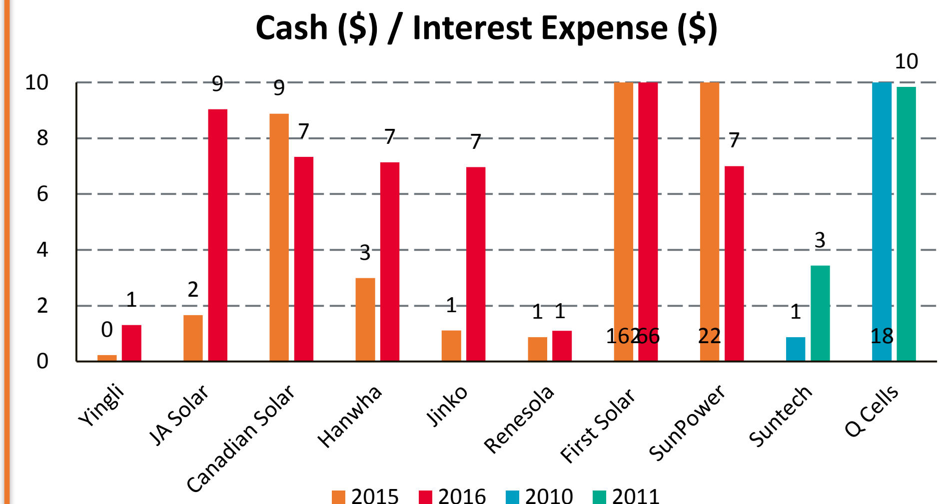
Sources: Company figures based on Q4 2016 (and previous) SEC filings by the respective companies .

Debt Load of Manufacturers

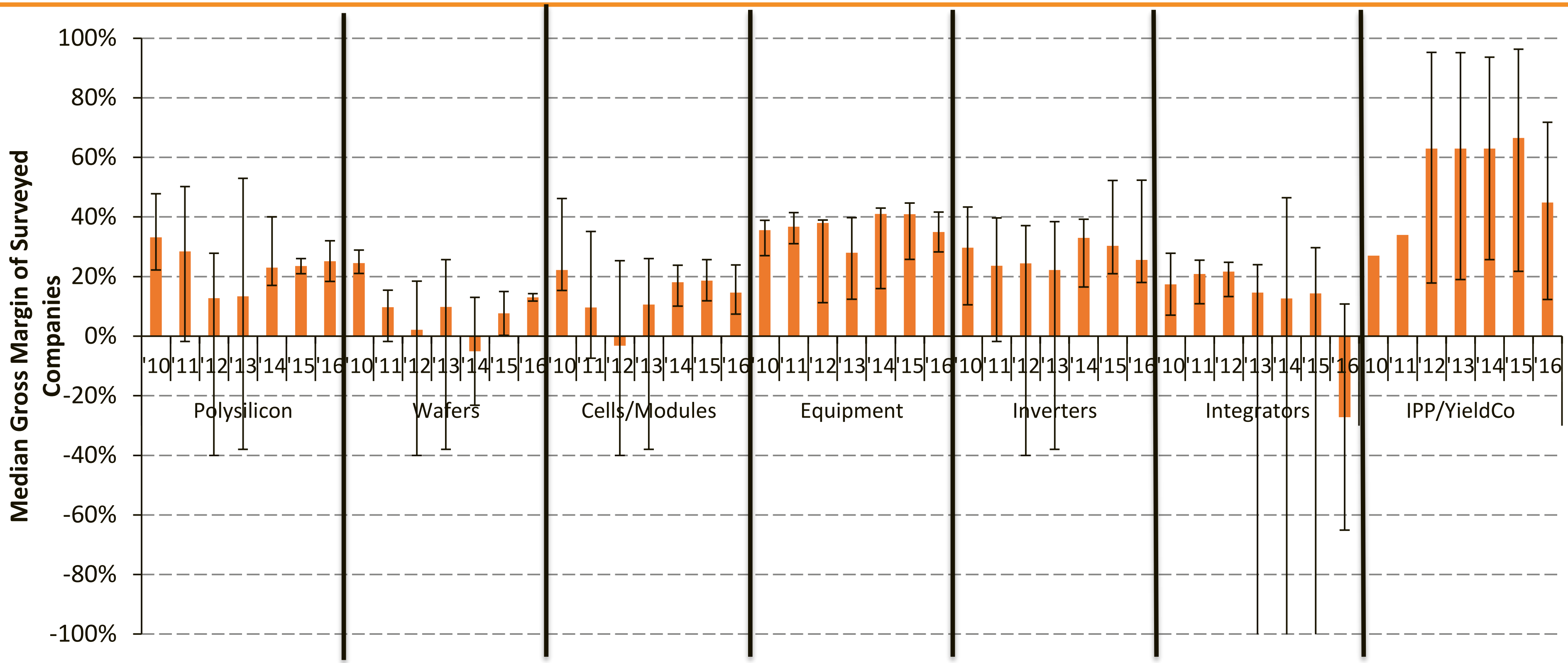




- Manufacturers show differing abilities to service their debts.
- In 2016, the above manufacturers had a median interest coverage ratio (relationship between operating profits, and interest expenses) of 1.37.
  - An interest coverage ratio below 1 means that a company's earnings were not sufficient to make payments on debt, and a company may have to draw from cash reserves to service loans.
- Many western companies have historically had higher cash-to-debt levels, and so could afford to draw upon cash.
  - First Solar and SunPower were able to incur restructuring charges in 2016 of $819 million and $207 million respectively, and were still able to service their debt.
  - Excluding the restructuring charges these companies would have healthier coverage ratios.
- Yingli's debt and cash levels are improving and doing better than historical levels achieved by bankrupt companies, such as Suntech and Q-Cells. That said, they will be challenged by a downturn in margins as well as finding the cash to make restructuring improvements to better compete.

"2016R" represents the ratio ***excluding*** restructuring charges
Sources: Corporate Filings (Q4 '16)

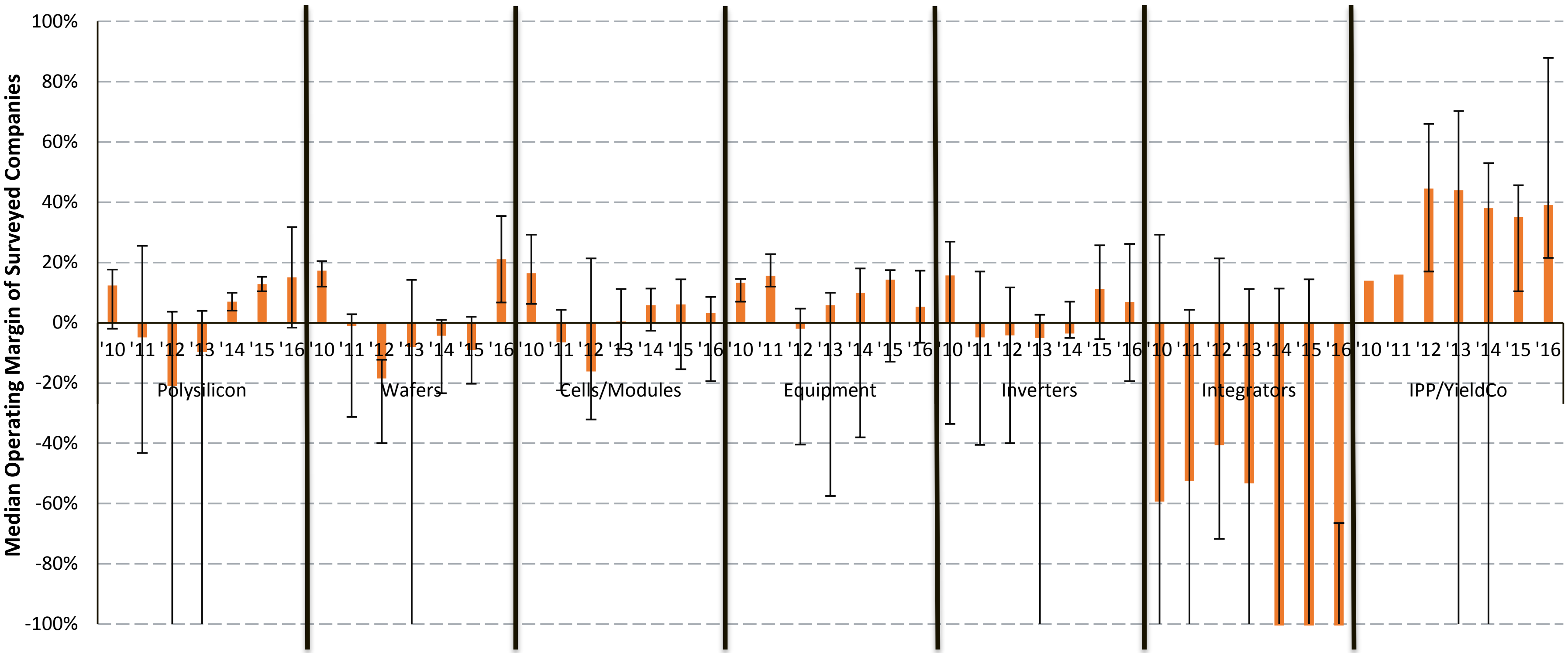
Gross Margin Across Supply Chain



- Gross margins generally dropped in 2016 though there was still substantial variation among individual companies.
- Yieldcos continue to get higher margins than other sectors of the supply chain, however their margins, on average, also dipped significantly in 2016, and had substantial variation.
  - There was a wide variation in profitability for integrators.

Sources: Company figures based on Q4 ’16 (and previous) SEC filings by the respective companies. Error bars represent high and low values of surveyed companies. Companies surveyed are: Wafers - LDK Solar, ReneSola, SAS Wafers, Wafer Works Corp., Solargiga; Poly - GCL-Poly, REC Silicon, Wacker, LDK Solar; Cells/Modules, Gintech ,Motech, First Solar, JA Solar, Yingli, Trina Solar, Canadian, PV Crystalox Solar ,Hanwha SolarOne, Jinko Solar, SunPower, LDK Solar; Integrators - Real Goods Solar, SolarCity, Vivint, SunEdison; Inverters - Power-One, SMA, Satcon, Enphase Energy, Advanced Energy Industries; IPP/Yieldco - Abengoa Yield, NRG Yield, NextEra Energy Partners, Northland Power Inc., Pattern Energy, Terraform Power, Sky Solar Holdings.

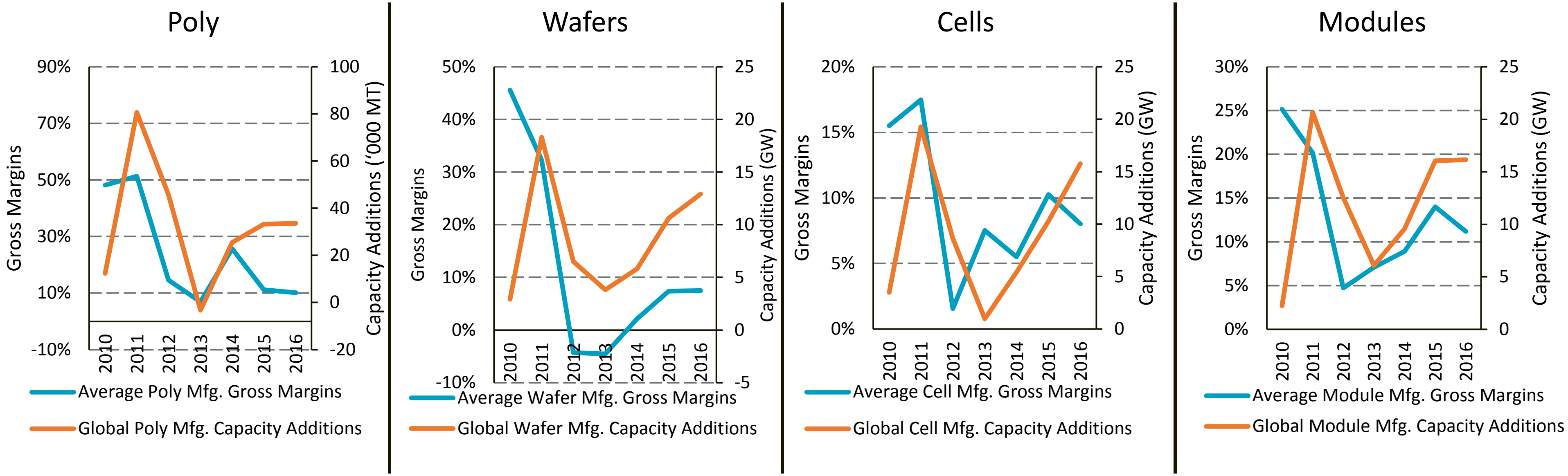
Operating Margin Across Supply Chain



- There was a wide variation in operating margins as companies try to gain market share and pursue new strategies.
  - There was substantial variation across the supply chain as integrators sacrifice short term profits to scale rapidly.
- Operating margin is not necessarily an indicator of corporate profitability, though with strong margins companies should eventually figure a way to profitability.

Sources: Company figures based on Q4 '16 (and previous) SEC filings and Annual Reports by the respective companies. Error bars represent high and low values of surveyed companies. Companies surveyed are: Wafers - LDK Solar, ReneSola, SAS Wafers, Wafer Works Corp., PV Crystalox, Solargiga; Poly - GCL-Poly, REC Silicon, Wacker, LDK Solar; Cells/Modules, Gintech ,Motech, First Solar, JA Solar, Yingli, Trina Solar, Canadian Solar ,Hanwha SolarOne, Jinko Solar, SunPower, LDK Solar; Integrators - Real Goods Solar, SolarCity, Vivint, SunEdison; Inverters - Power-One, SMA, Satcon, Enphase Energy, Advanced Energy Industries; IPP/Yieldco - Abengoa Yield, NRG Yield, NextEra Energy Partners, Northland Power Inc., Pattern Energy, Terraform Power, Sky Solar Holdings.

Profit vs. Manufacturing Capacity Additions



- Manufacturing capacity additions slumped in 2012–2013 following the slump in gross margins across the supply chain but rose again following the increase in margins.
- Margins started to fall again in 2016; while capacity additions generally rose in 2016, they significantly dropped Q/Q toward the end of the year.

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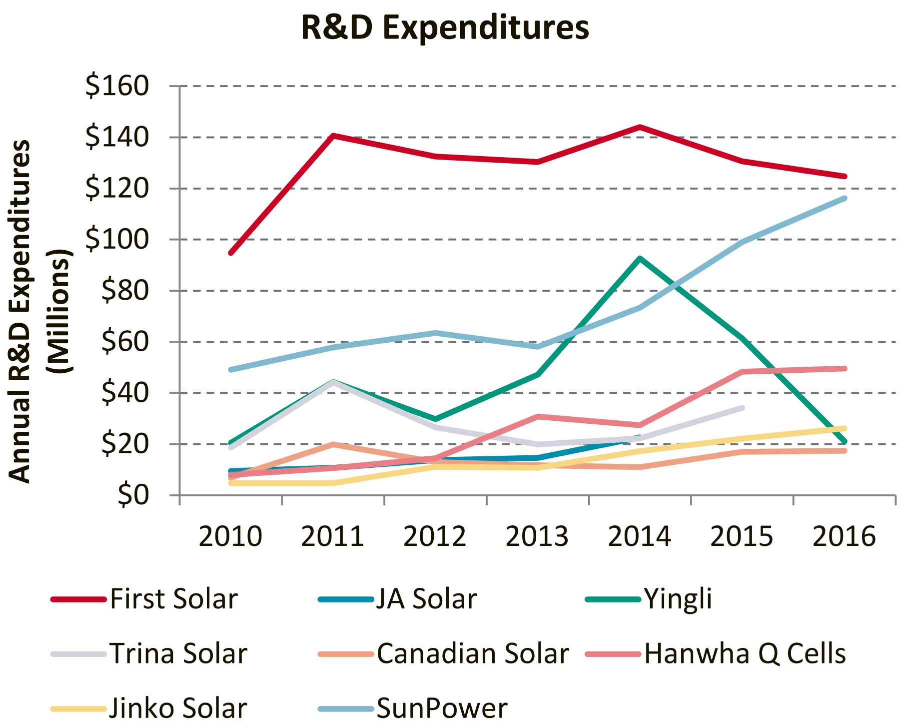
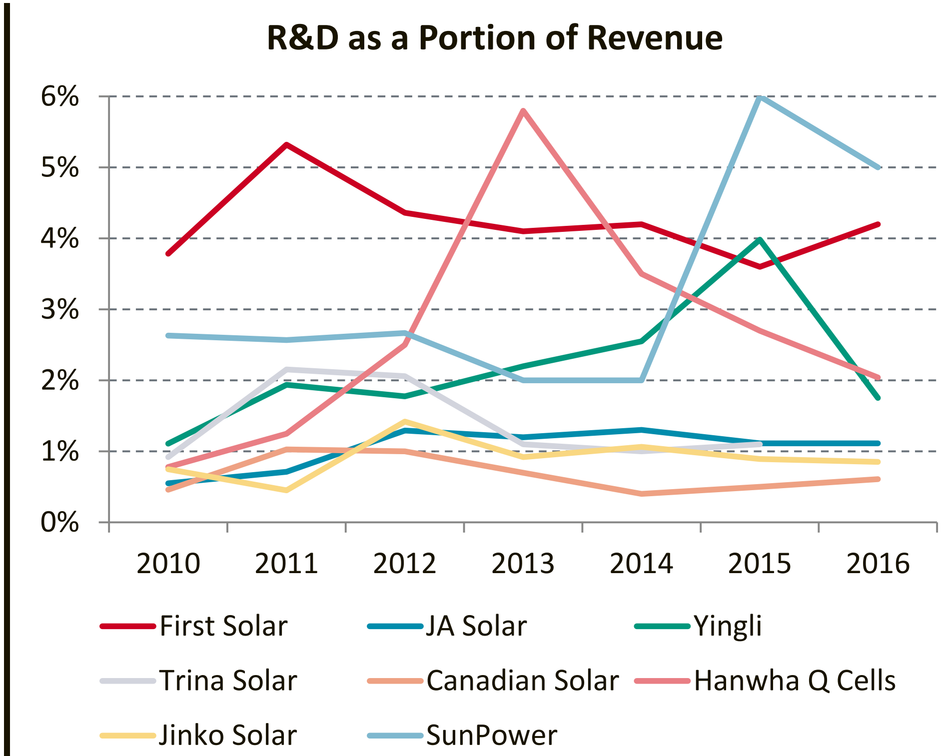
Sources: IHS PV Integrated Market Tracker Q4 2016. December 23 2016.

Research & Development





- In 2016, these companies spent over $380 million on R&D, down 5% YoY.
- First Solar continues to lead in R&D spending, though SunPower has been increasing its R&D expenditures annually.
- The majority of Chinese manufacturers are providing lower but relatively consistent levels of funding to research.
  - Yingli significantly cut its R&D budget as it endeavors to avoid bankruptcy.

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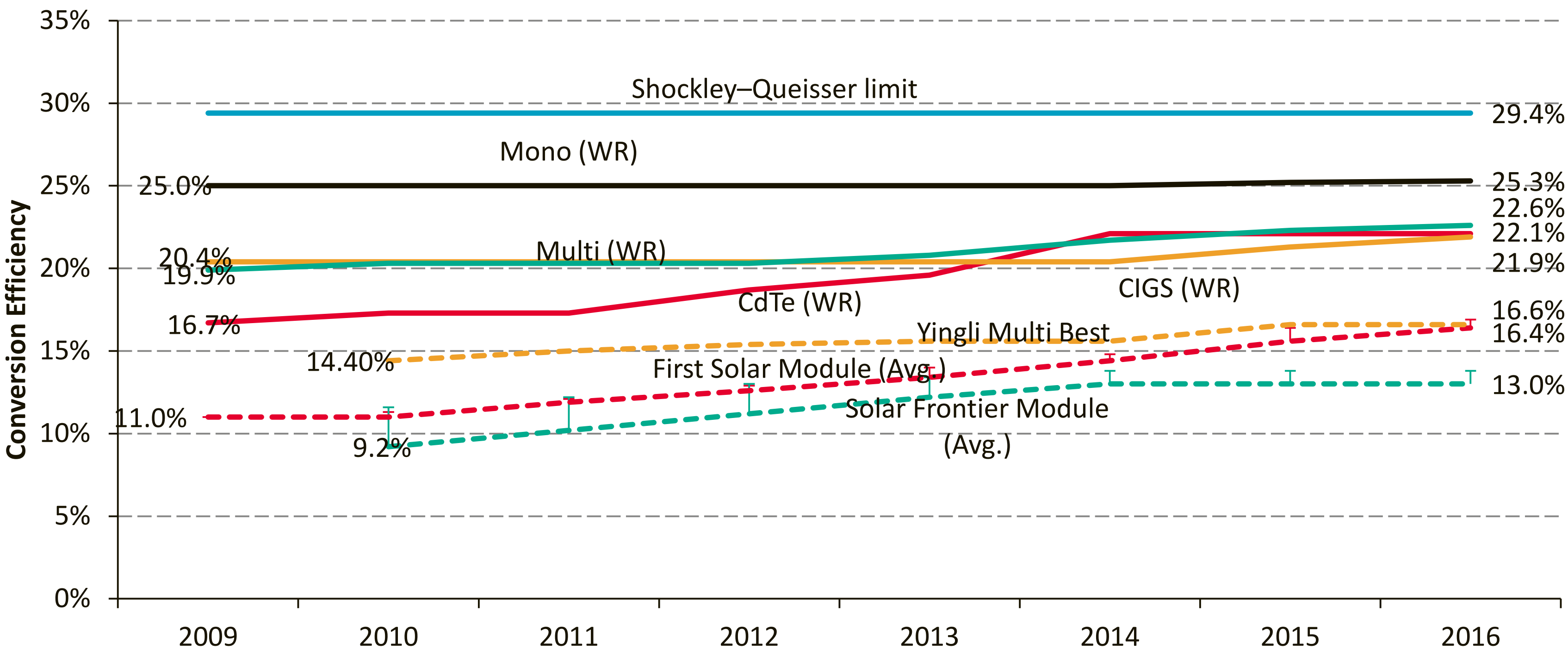
Sources: Company figures based on Q4 2016 (and previous) SEC filings by the respective companies.

PV Efficiency Improvements



- Most technologies saw slight increases in efficiency in 2016.
- CIGS/CdTe now have similar WR efficiencies to multi c-Si and average-efficiency CdTe modules are closing the gap.
- A key question is whether CIGS/CdTe will be able to close the gap with mono c-Si world records or if there are structural barriers preventing this from occurring.

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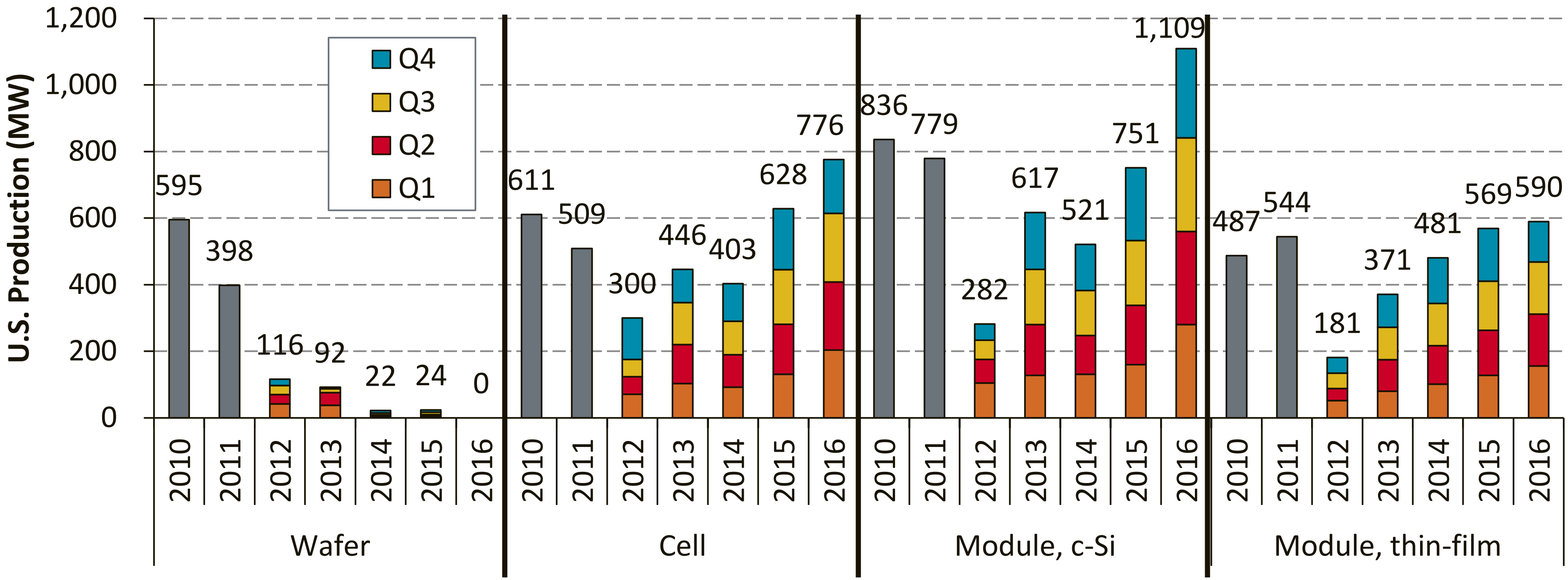
Sources: Corporate press releases and public filings, NREL World Records.

U.S. Manufacturing



- U.S. module and cell production increased again in 2016, growing y/y 29% and 24% respectively.
  - U.S. tariffs on Chinese modules and cells, and a growing U.S. market, contributed to increased production levels.
  - In 2016, module production was split 65% c-Si, 24%, CdTe, and 11% CIGS.
- Wafer production halted in the United States in 2016 as SunEdison consolidated its R&D facilities; however, wafer production in the U.S. effectively ended a few years ago.

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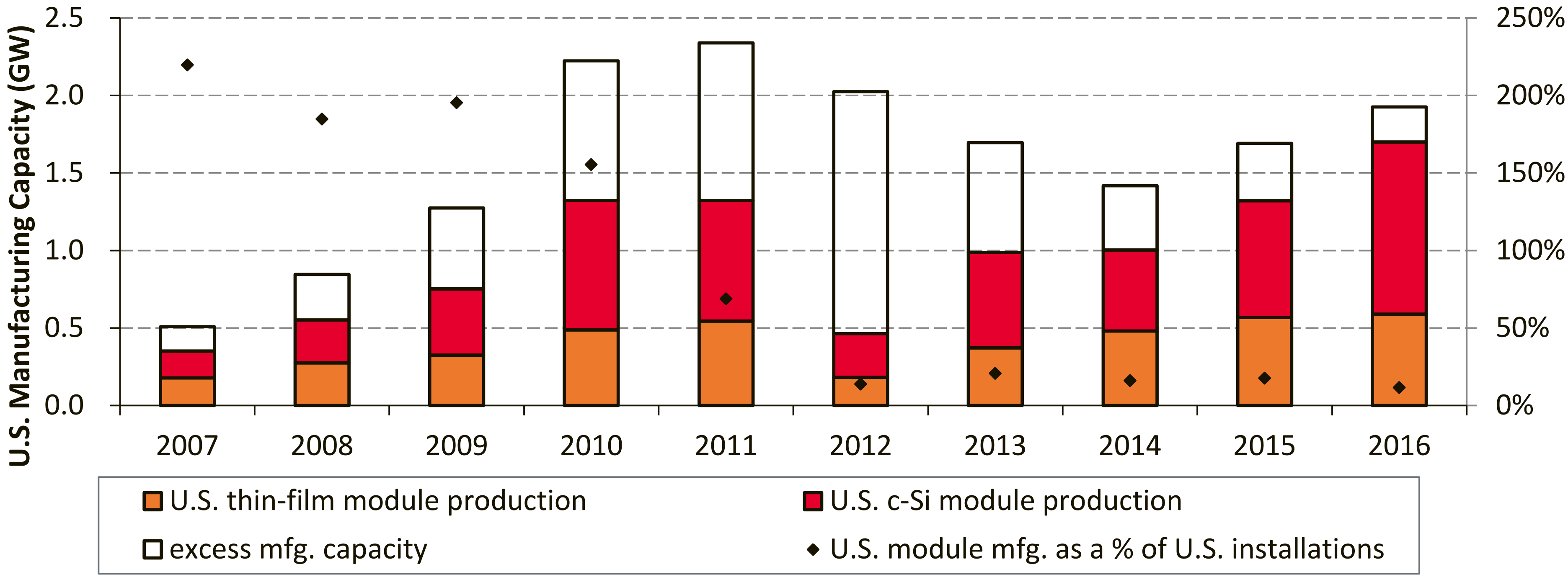
Source: GTM Research & SEIA. "U.S. Solar Market Insight: Q4 2016."

U.S. Module Manufacturing vs. U.S. Deployment



- Pre- 2011, the United States was a net-exporter of PV modules; in 2016 U.S. module production surpassed its previous peak from 2011; however, the U.S. domestic deployment market has increased by a factor of 16.3 since 2010.
  - U.S. manufacturing represented 12% of U.S. deployment in 2016.

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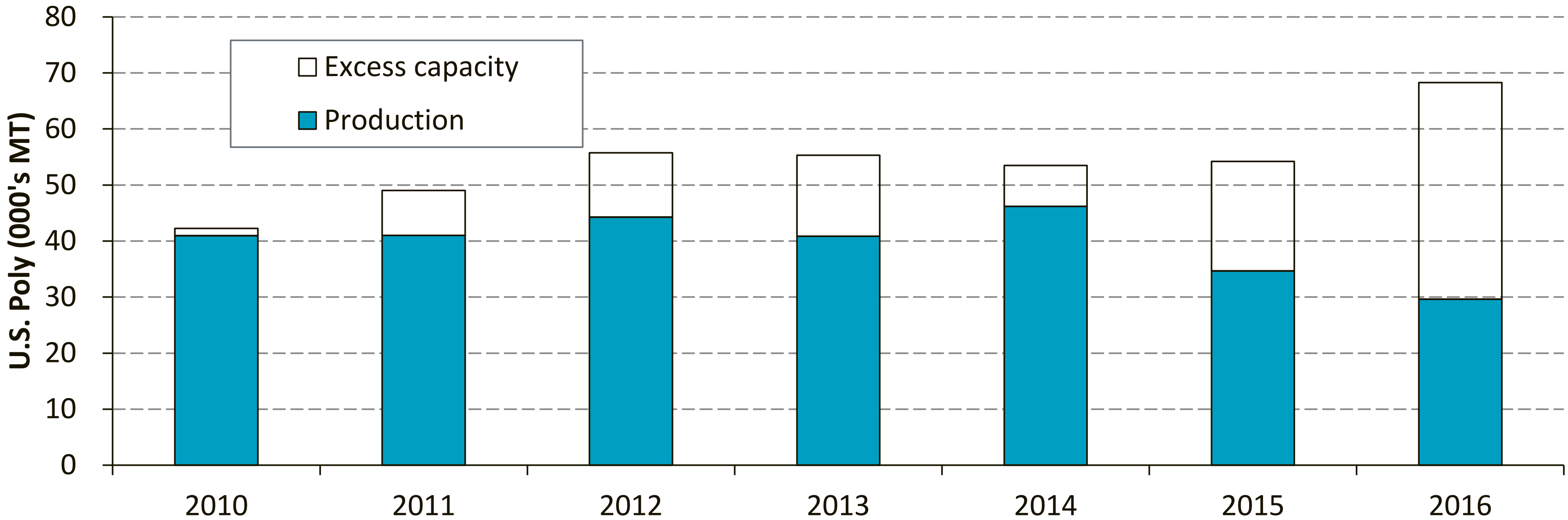
Source: GTM Research & SEIA. “U.S. Solar Market Insight: Q4 2016.”

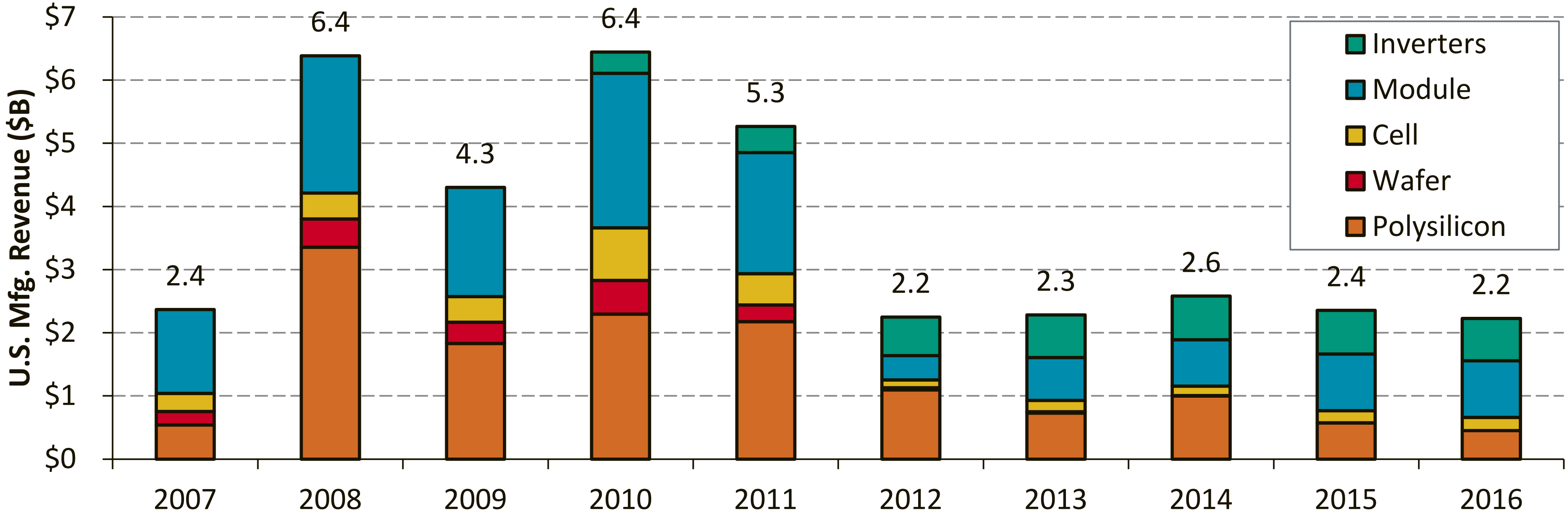
U.S. Polysilicon Manufacturing



- From 2010 to 2014, U.S. polysilicon production was relatively flat; however, China's antidumping tariffs, which were effectively implemented in August 2014, appear to be having an effect on U.S. polysilicon manufacturing.
  - Poly utilization rate was down from 86% in 2014 to 43% in 2016.

Source: GTM Research & SEIA. "U.S. Solar Market Insight: Q4 2016."

Estimated U.S. Manufacturing Revenue



- In 2016, estimated U.S. PV & inverter revenue was $2.2B, fairly flat since 2012 but down 65% from ’10.
  - Poly revenue decreased 55% from 2014 to 2016 due to a 36% decrease in production and 29% decrease in price.
  - Module and inverter revenues were flat y/y as the increase in production was counteracted by the decreased in price.
  - Modules, inverters and polysilicon were 40%, 30%, and 20% of U.S. revenue, respectively.

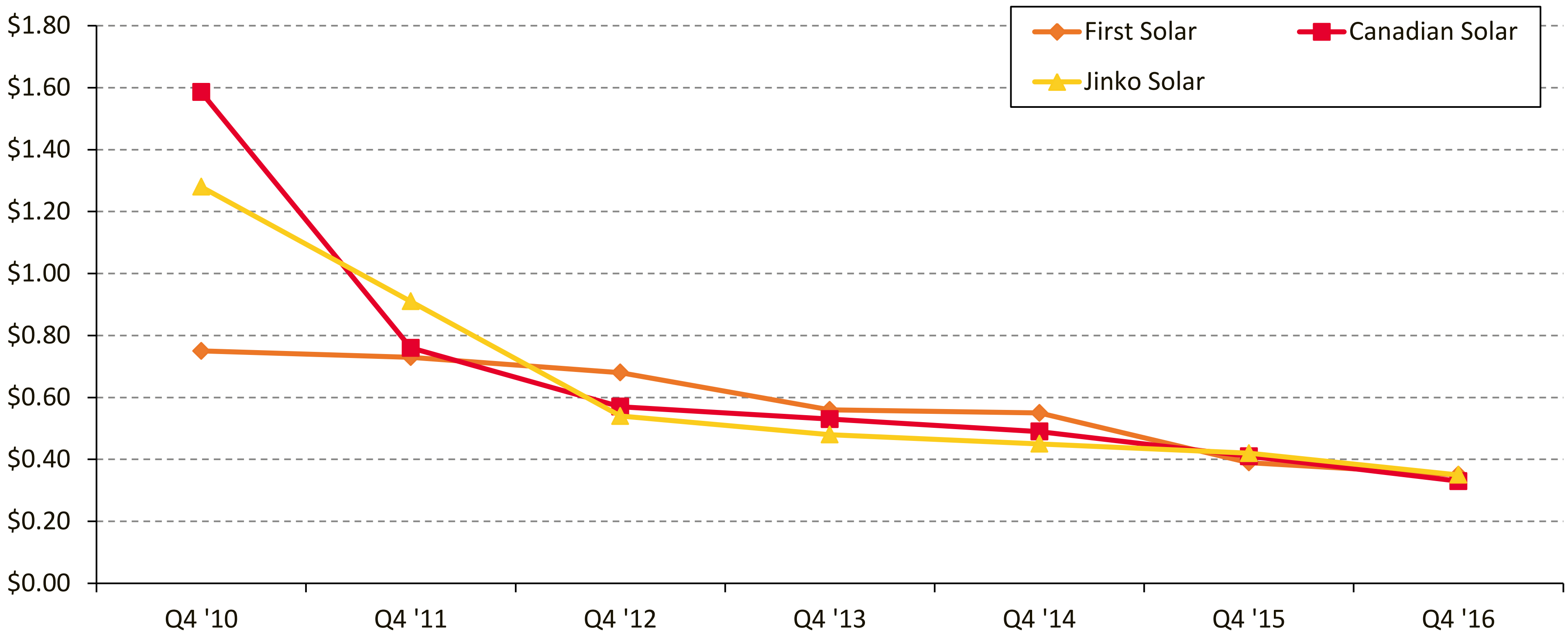
Note: measured by U.S. production x average component price

Sources: production of wafer/cell/module 2007-11: GTM "Wafer Cell Module Database 2012". June 2012. Polysilicon 2007-11: IEA, U.S. NSR, 2007-2011. Wafer/cell/module/poly 2012-5 (production and price) : GTM/SEIA “U.S. Solar Market Insight Q4 ’15” (March ‘16). Price, 2007-11: Photon Consulting, "Solar Annual 2012" & "Solar Annual 2009“; 2014 production and price: GTM/SEIA “U.S. Solar Market Insight 2015 Year-in-Review” (March ‘16).

Agenda

- State and Federal Updates
- Global Market Updates
- U.S. Deployment
- U.S. Pricing
- Global Manufacturing
- Component Pricing
- Market Activity

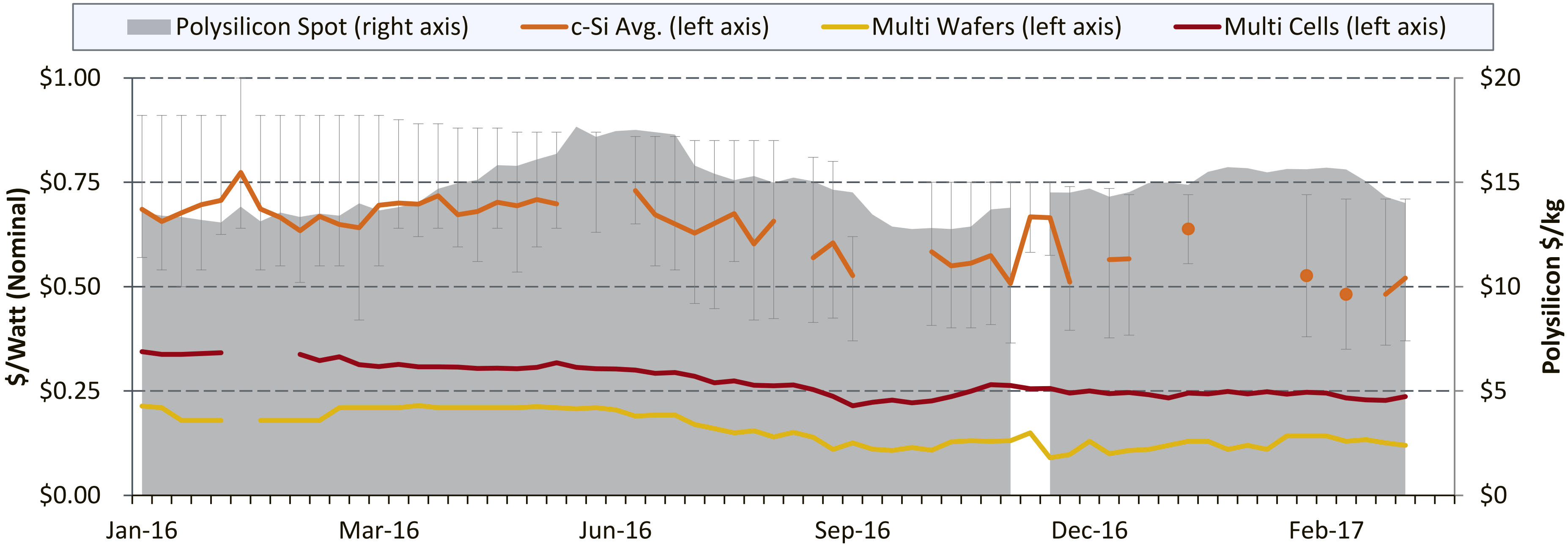
PV Manufacturers' Cost



- In Q4 '16 module costs were between $0.33/W and $0.35/W.
  - Q4 '16 costs from the above companies were, on average, 15% less than Q4 '15, though these three companies may not be representative of the industry as a whole.

Sources: Company figures based on Q4 '16(and previous) SEC filings by the respective companies. Deutsche Bank (12/17/15 (4/26/16) (3/31/17).

Module, Cell, Wafer, and Polysilicon Price



- Module and component prices continued to decline in the first quarter of 2017 after rapid declines in 2016.
  - BNEF reports Q1 2017 price reductions. Q/Q, for modules (18%), cell (4%), wafer (8%), and poly (4%).
  - From Q1 2016 to Q1 2017 BNEF reports price reductions for modules (25%), cell (23%), and wafers (43%), but an increase of poly prices by 3%.
- Despite the general consensus of a lower-priced environment, there are a range of reported market prices, due in part to geographic differences, variations in order size and the difference between delivered prices versus booked prices.

Note: Error bars represent high and low quotes Module pricing reflects orders of approximately 1 MW; bigger orders are more likely to receive favorable pricing .

Source: BNEF Solar Spot Price Index (04/07/17).

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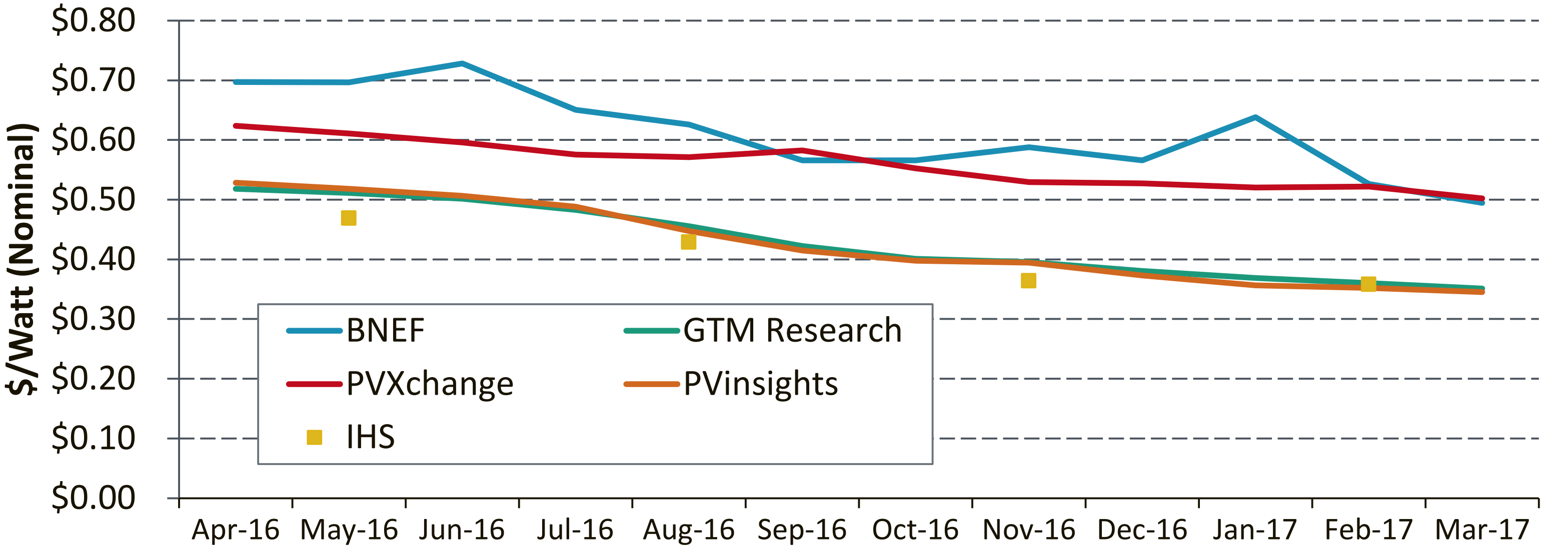
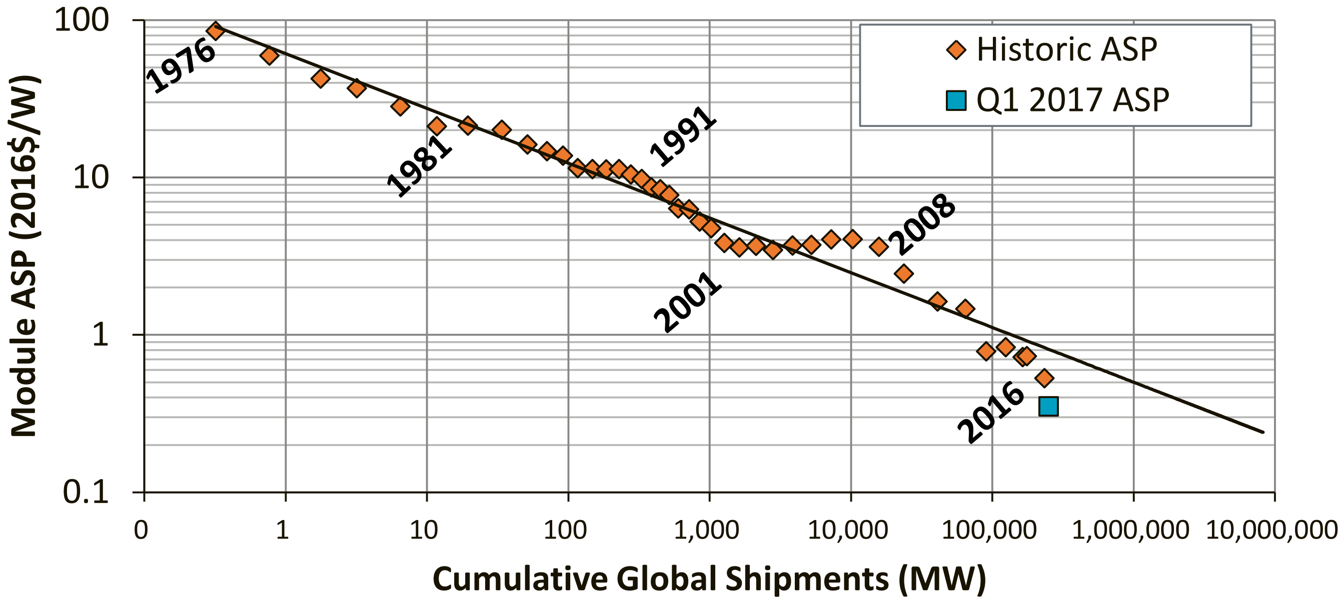
Different Estimates of Module ASP



- Estimates of module ASP vary be source; as of March 2017, most estimates quote module ASP as $0.35/W or $0.50/W.
  - PVXchange only reports European markets data, which currently has a module price-floor agreement in place with many Chinese companies (price floor currently ~$0.49/W)
  - BNEF explicitly tracks smaller orders, approximately 1 MW in size, in their spot pricing index; their estimate of larger orders, above 10 MW, is consistent with the lower estimated prices.
  - Upper end pricing may reflect higher-priced markets or products, or smaller buyers.

Sources: BNEF Solar Spot Price Index (04/07/17); GTM Research (February 2017, April 2017); IHS Technology (December 2016); PVInsights (04/07/17); PVXchange (04/07/17); Mercom (01/26/17) .

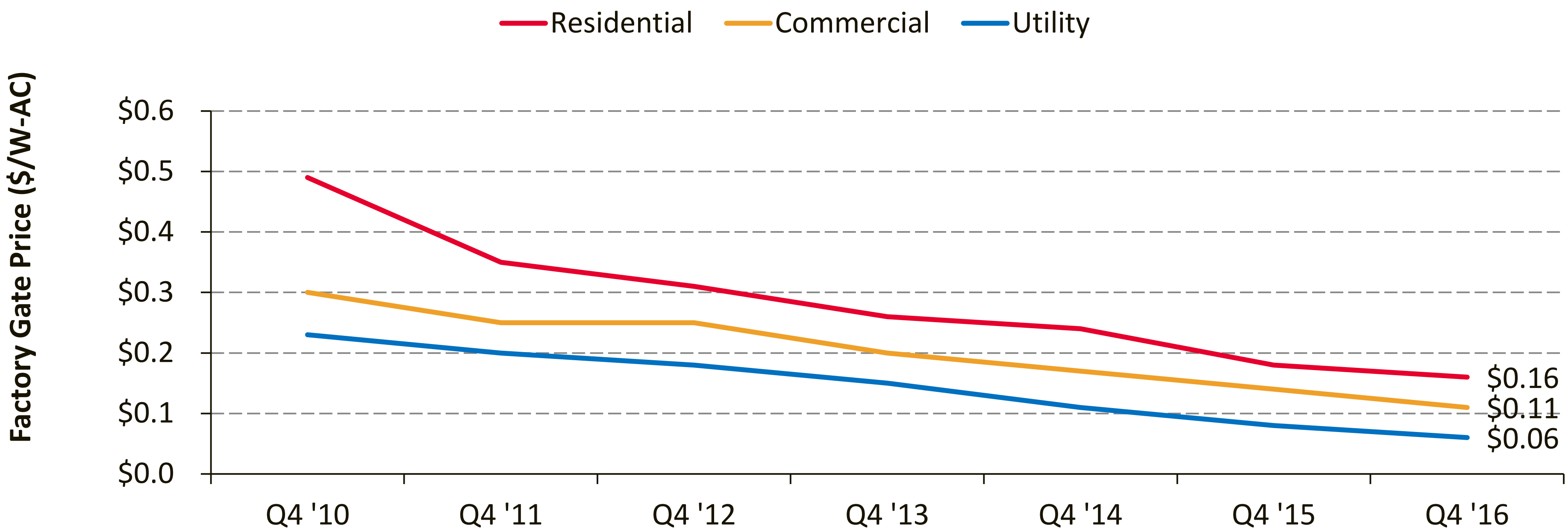
Experience Curve



- This experience curve displays the relationship, in logarithmic form, between the average selling price of a PV module and the cumulative global shipments of PV modules. As shown, for every doubling of cumulative PV shipments there is on average a corresponding ~21% reduction in PV module price.
- Since 2012, module ASP has been below the historical experience curve, which would have extrapolated that the industry would have needed to produce 2.8 TW of panels to get to Q1 2017 module ASP—the industry has produced 250 GW – 300 GW.

Sources: For 2001-2016: Paula Mints. "Photovoltaic Manufacturer Capacity, Shipments, Price & Revenues 2016/2017." SPV Market Research. Report SPV-Supply5. April 2017. For 1999-2000: Paula Mints. "Photovoltaic Manufacturer Capacity, Shipments, Price & Revenues 2014/2015." SPV Market Research. Report SPV-Supply3. April 2015. For 1984-1998: Navigant Consulting (2010), Photovoltaic Manufacturer Shipments, Capacity & Competitive Analysis 2009/2010, Report NPS-Supply5 (April 2010). For 1980-1984: Navigant Consulting (2006), Photovoltaic Manufacturer Shipments 2005/2006, Report NPS-Supply1 (August 2006). For 1976-1980: Strategies Unlimited (2003), Photovoltaic Manufacture Shipments and Profiles, 2001-2003, Report SUMPM 53 (September 2003).

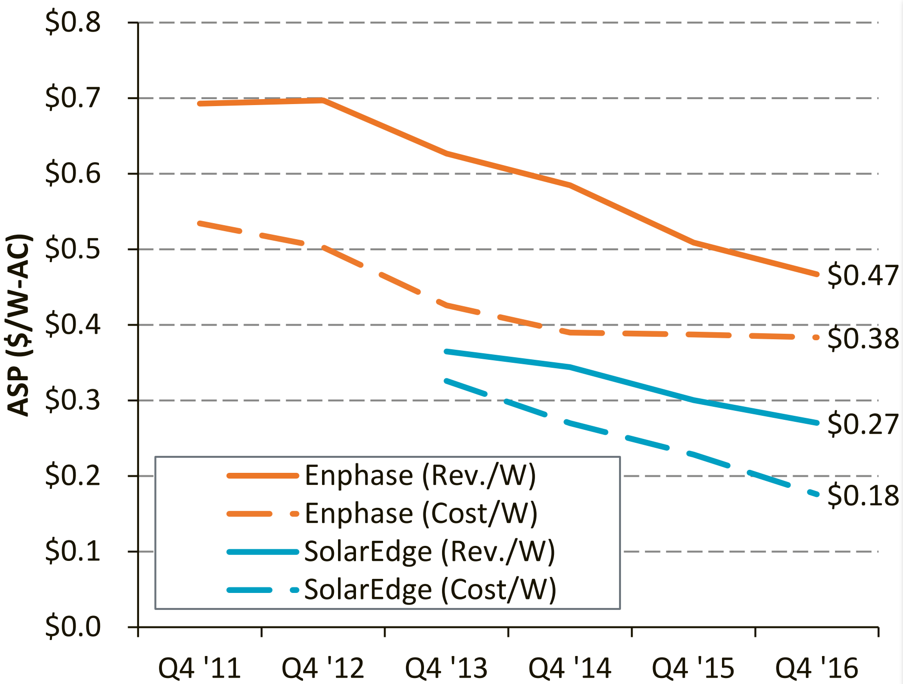
Inverter Pricing

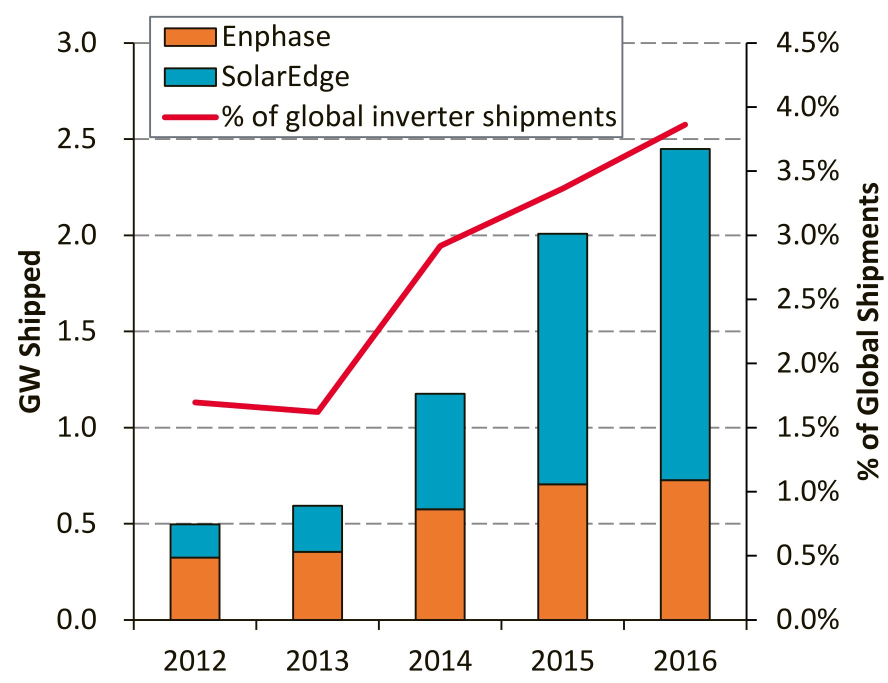


- Since Q4 ‘10, inverter prices have fallen by 63%–74%.
- From Q4 ’15 to Q4 ‘16 inverter prices dropped 11%–25%.

Source: GTM/SEIA “Solar Market Insight 2016 Year-in-review.”

Enphase Microinverters and SolarEdge DC-Optimized Inverter Systems





- From Q4 ‘15 to Q4 ‘16 Enphase inverter and SolarEdge optimizer prices fell 8% and 10% respectively.
  - SolarEdge costs also decreased by 23% while Enphase costs have been flat for two years.
- SolarEdge shipped 1.7 GW in 2016—23% growth y/y; Enphase shipped 0.7 GW in 2016—up 3% y/y.
  - SolarEdge and Enphase shipments have increased from approximately 1.7% of total global shipments in 2012 to 3.9% in 2016.

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Sources: Enphase/SolarEdge public filings. Global inverter shipments from GTM Research.

Agenda

- State and Federal Updates
- Long-term Solar Projections
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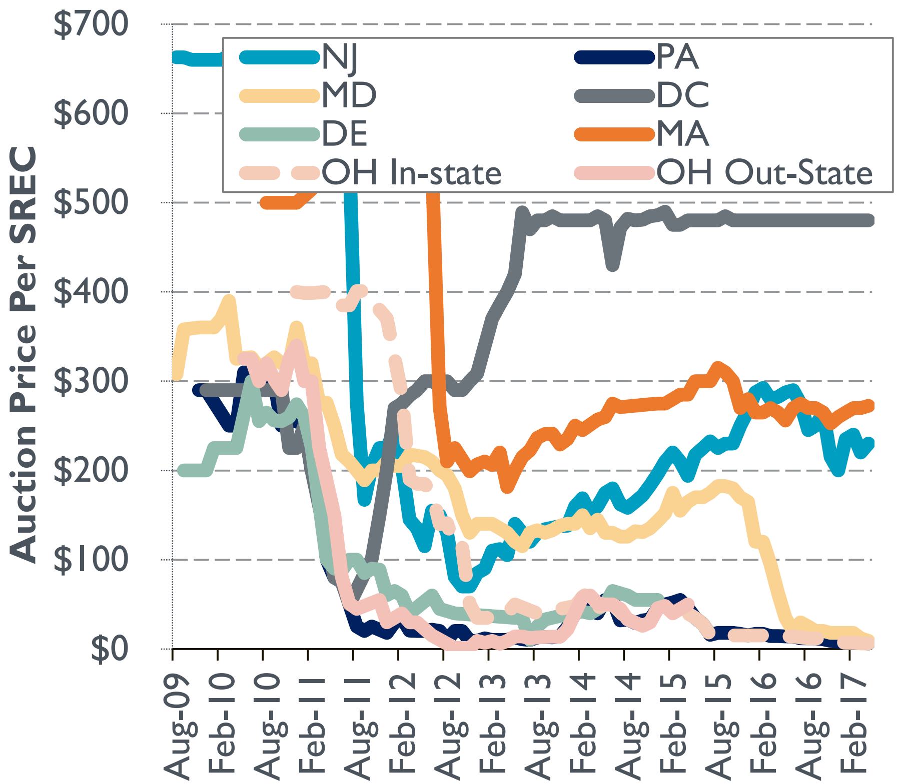
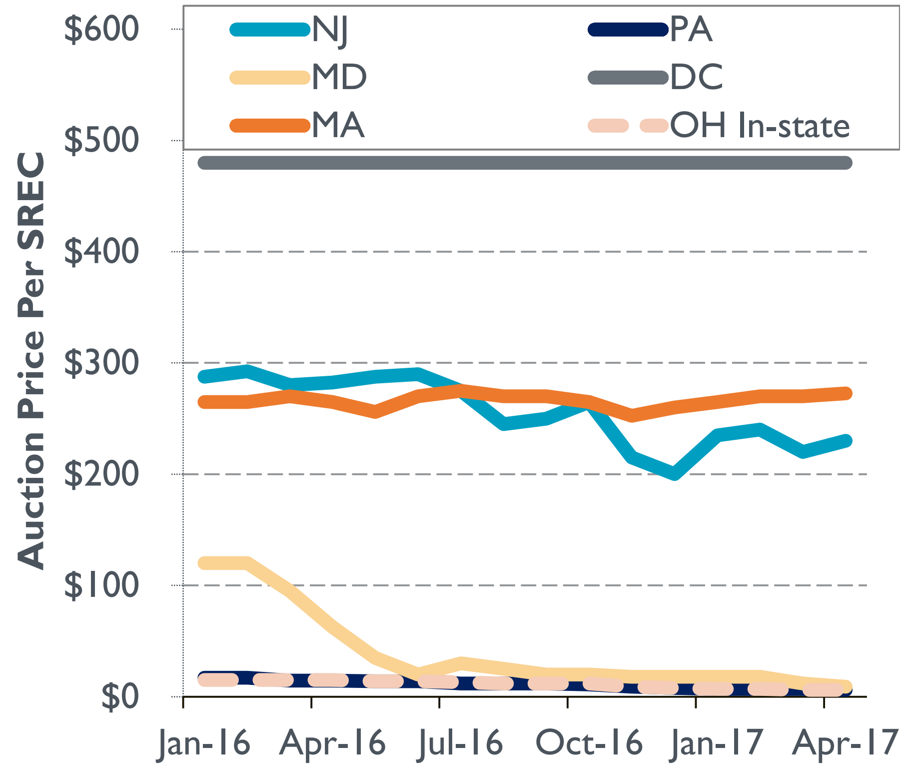
SREC Markets





- SREC prices saw dramatic changes in some markets and stability in others.
- Ohio, Pennsylvania and Maryland saw drops in SREC value in 2016.
  - The value of MD SRECS decreased 93% from January 2016 to April 2017, as the state approached its RPS cap; the state raised its RPS cap in February 2017, which should place upward pressure on SRECs, as the cap increased.

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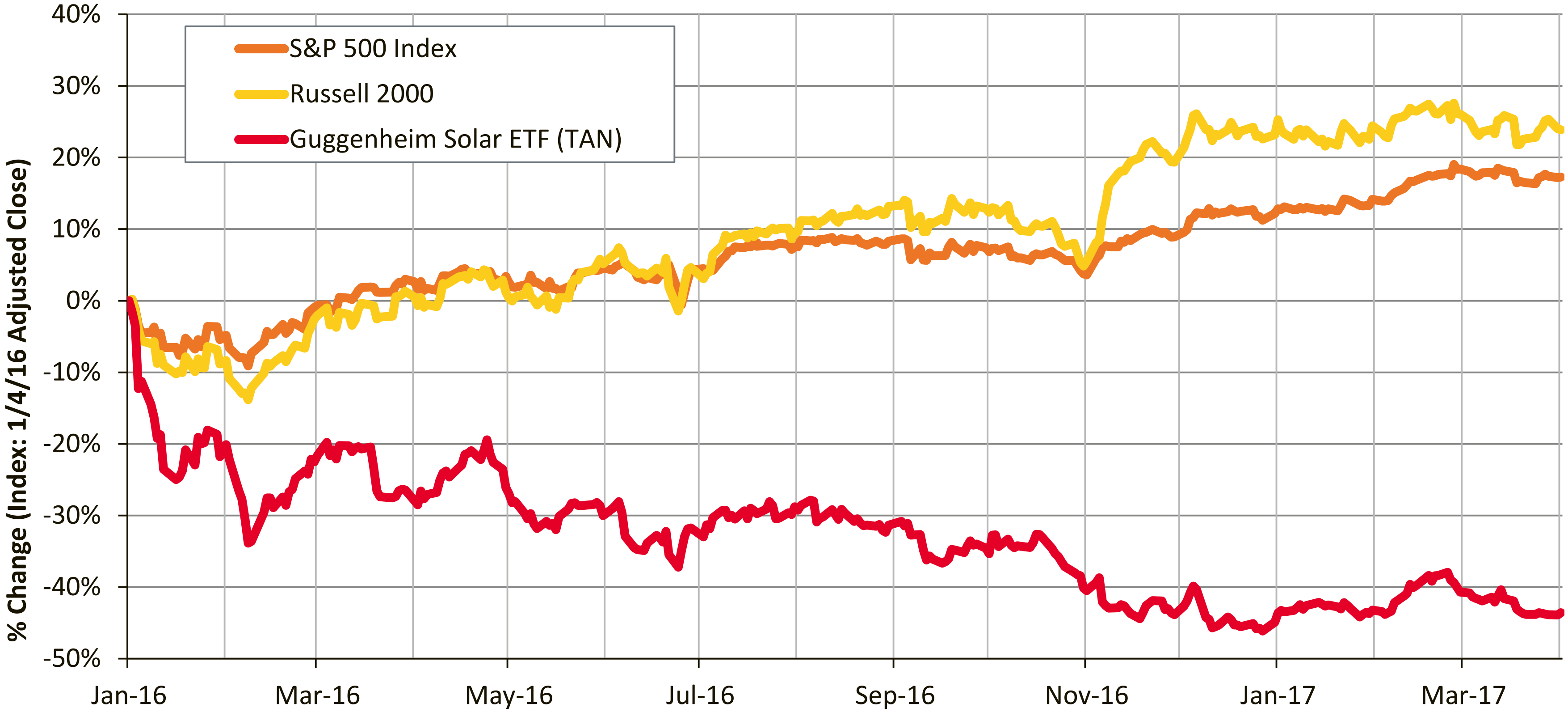
Source: Blog, SRECTrade, www.srectrade.com (accessed April 14, 2017); Utility Dive (February 3, 2017)

Market Activity

- Solar stocks saw significant losses in 2016, but began to track more closely to the broader market in Q1 2017.
  - TAN was ↑2% in Q1 2017, after seeing large losses in 2016.
  - S&P 500 was ↑4.5%, Russell 2000 was flat, over the same time period.



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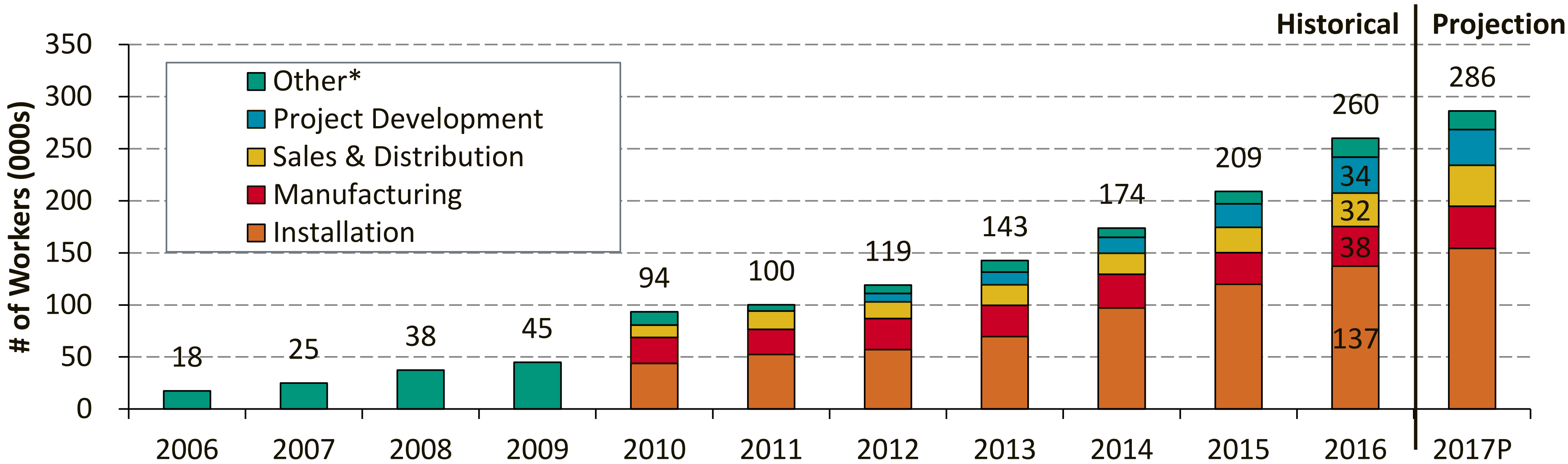
Notes: Average market cap. of securities in TAN was $9.8 Billion (12/31/16), Russell 2000, $1.6b (6/27/16).
Sources: Stock Market: YahooFinance (04/4/17).

U.S. Solar Workforce



- As of January 2017, the U.S. solar industry employed 260,000 workers, adding 51,000 jobs in 2016.
  - This represents the fourth straight year of 20%+ workforce growth.
  - Installations jobs represented 53% of total U.S. solar jobs in 2016; however, other areas had higher growth rates. For example, manufacturing jobs grew 26% y/y to over 38,000 and are expected to grow again in 2017.

*Changes in the number of jobs in the "Other" category between years are not necessarily a reflection of actual increases or decreases in employment, but may instead be due to changes in the types of jobs included in this category.

Source: The Solar Foundation, "The National Solar Jobs Census 2015." January 2017.

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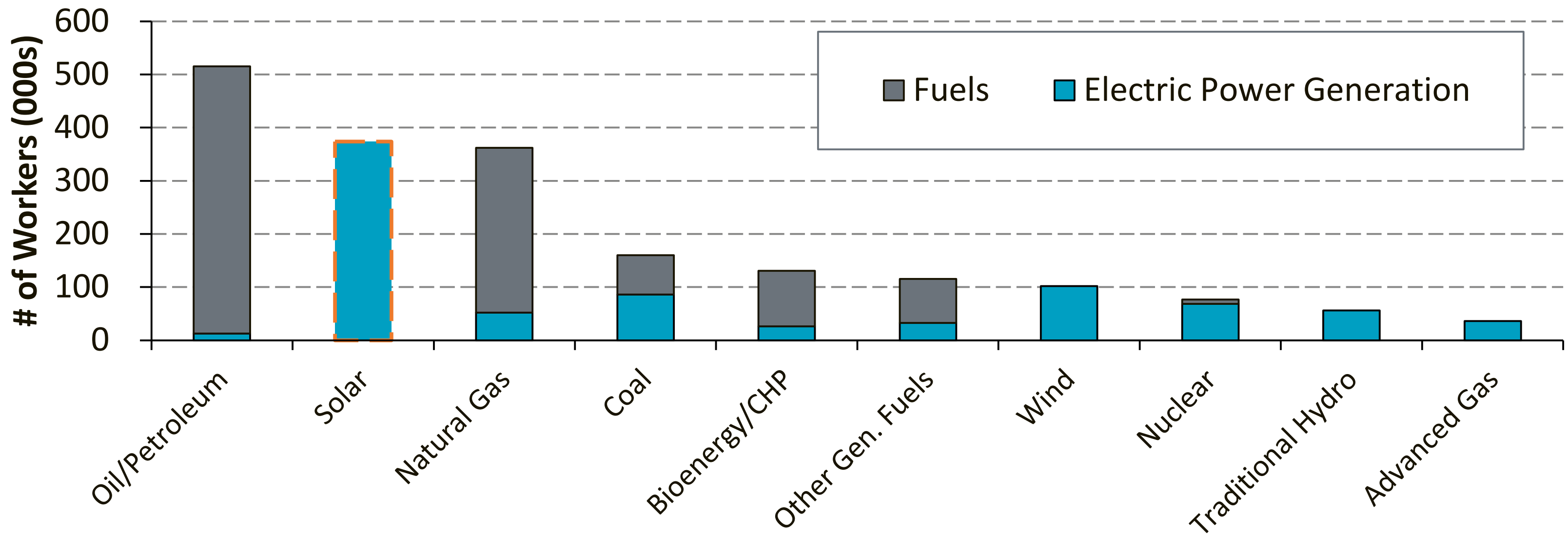
U.S. Solar Workforce (cont.)



- While 260,000 people in the United States spend at least ½ of their time on solar-related work, 374,000 employees spend some time working for the solar industry—larger than every other energy sector but petroleum.
- The solar industry is creating jobs at a rate 17 times greater than the overall U.S. economy.
  - In 2016, *one in fifty* new jobs added in the United States was created by the solar industry.
- In 2016, women represented 28% of the solar workforce; veterans accounted for 9.3%—both percentages represent a growth y/y.
- Nearly 80% of solar employers report that they have some difficulty finding qualified employees they need, despite installers offering a medium wage of $26/hr.

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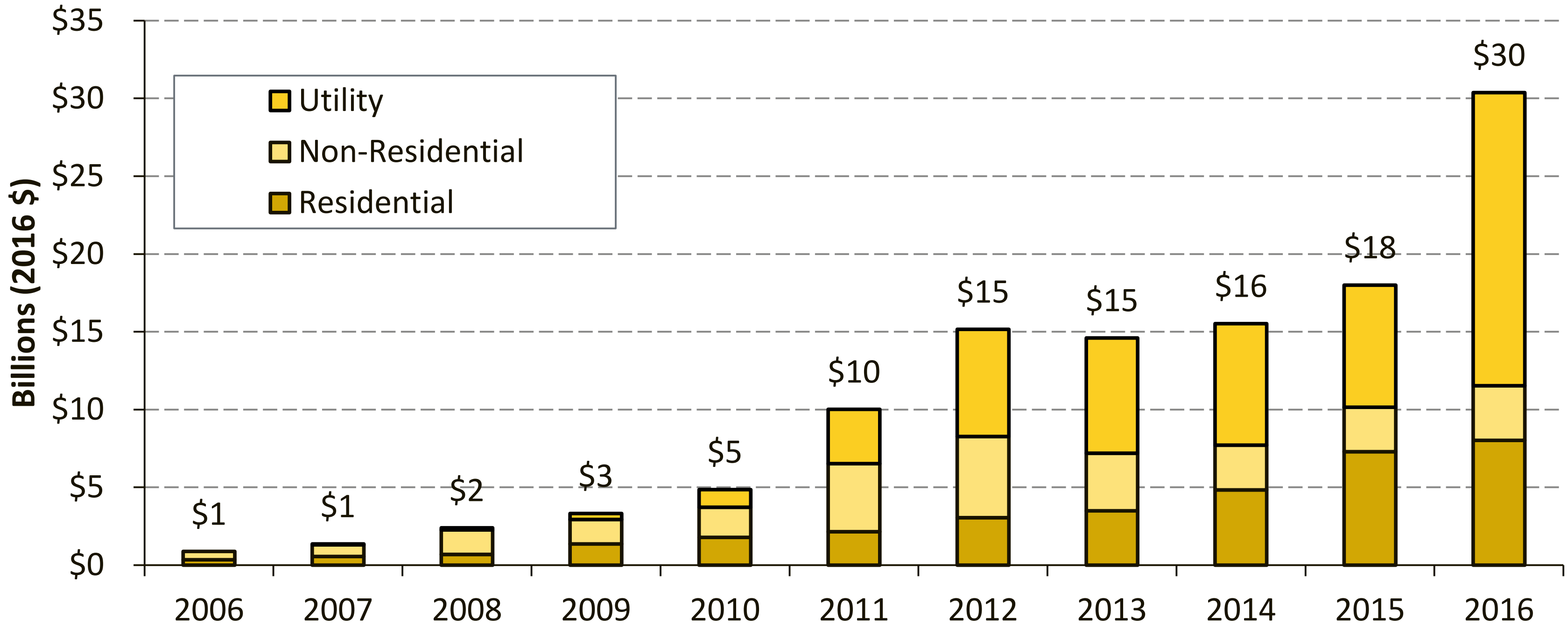
Source: The Solar Foundation, "The National Solar Jobs Census 2015." January 2017.

Estimated Value of U.S. Solar Installations

- The estimated value of U.S. PV Installations in 2016 was approximately $30 billion.
  - This represents an increase of 69% over 2015.
  - 62% of 2016 annual value was in the utility sector, 26% in the residential sector, and 12% in the non-residential sector.
- Worldwide installations in 2016 was approximately $100–$150 billion.



Sources: PV installations: DOE "2010 Solar Market Trends Report" (U.S. '06-'09); GTM Research / SEIA "Solar Market Insight 2016 Year in Review" (U.S. '10-'16). PV Price: LBNL "Tracking the Sun VIII" and "Utility-scale Solar" (2006-09); NREL "U.S. Solar Photovoltaic System Cost Benchmark Q1 2016"; U.S. Jobs: Solar Foundation "National Solar Jobs Census 2015" ('10-'15); SEIA Estimate ('06-'09).

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Thank You

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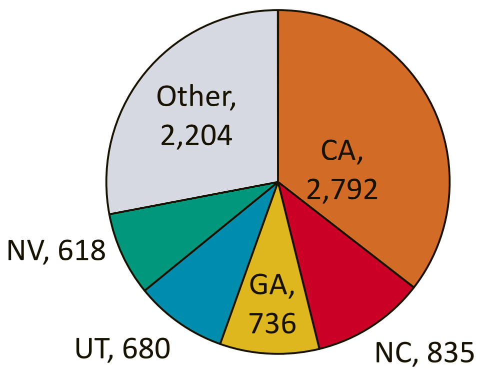
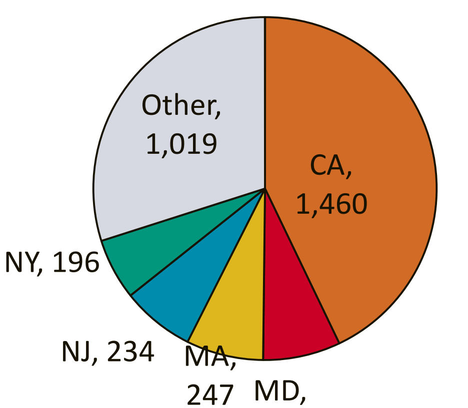
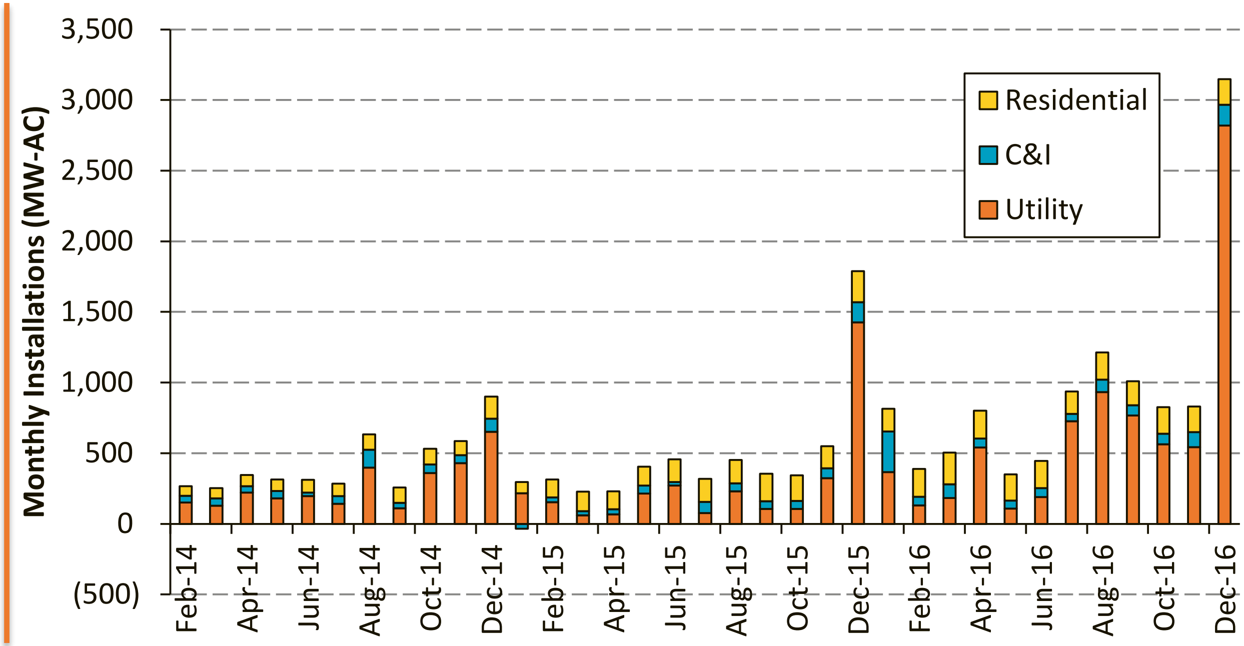
U.S. Installation Breakdown

U.S. PV Utility-Scale Installations by State (MW_{AC}), 2016



U.S. PV Distributed Installations by State (MW_{AC}), 2016





- The United States installed almost 4 GW_{DC} of PV in December 2016 and almost 1 GW_{DC} for 8 months in 2016.
- Utility-scale PV deployment has much greater seasonal variation than distributed PV deployment.

Sources: EIA, "Electric Power Monthly," forms EIA-023, EIA-826, and EIA-861 (February 2017).
Notes: EIA monthly data for 2016 are not final. Additionally, smaller utilities report information to EIA on a yearly basis, and therefore, a certain amount of solar data has not yet been reported.

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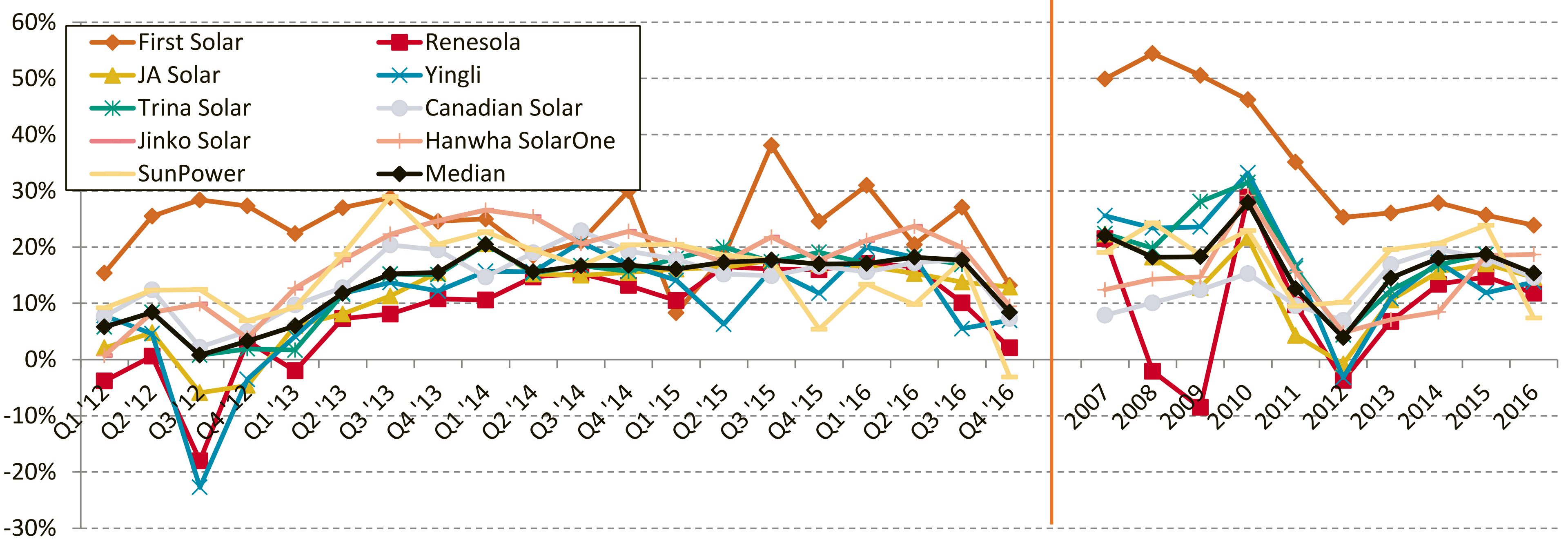
PV Manufacturers' Gross Margins



- Industry gross margins decreased by 55% Q3-Q4 '16, with some variation among individual companies:
  - 8% median gross margin of above companies in Q4 '16
  - 18% in Q3 '16
  - 17% in Q1 '16
  - 17% in Q4 '15.
- Drop in margin is consistent with reports of declining module prices.

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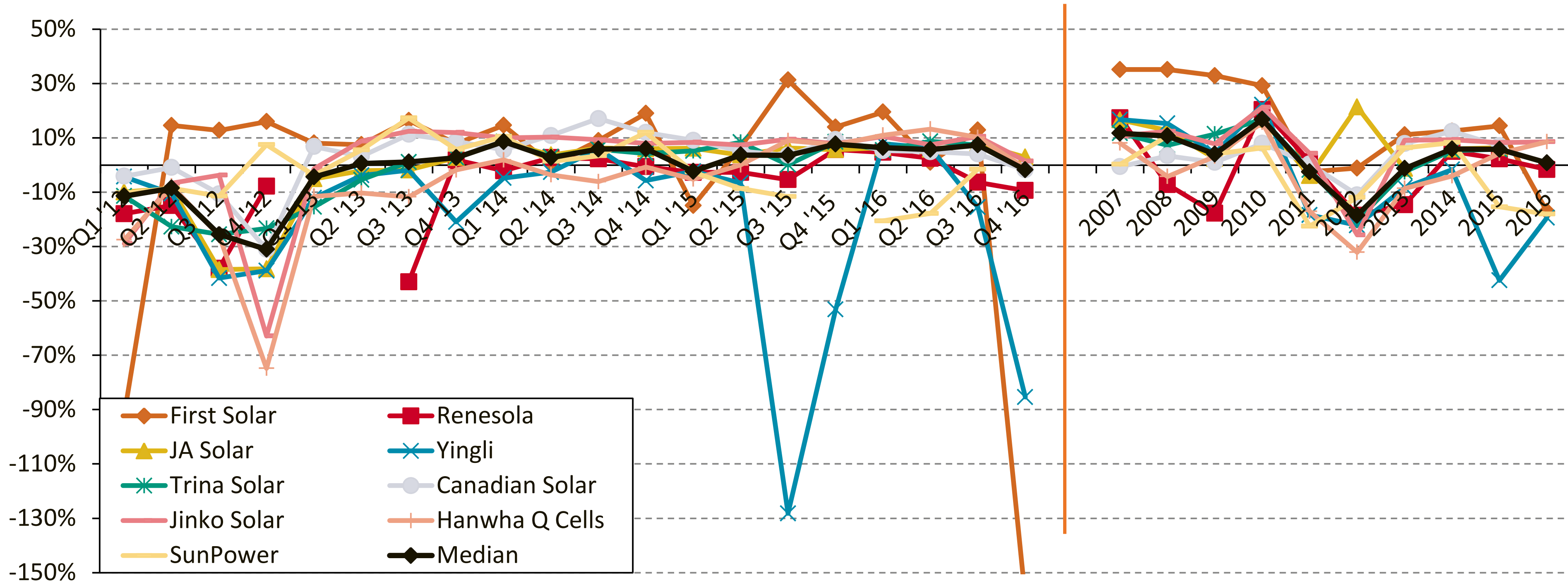
Sources: Company figures based on Q4 '16 (and previous) SEC filings by the respective companies.

PV Manufacturers' Operating Margins



- Operating margins saw a downturn in 2016, with some companies posting operating losses:
  - -2% median operating margin of the above companies in Q4 16
  - Previous 8 quarters averaged 1%.

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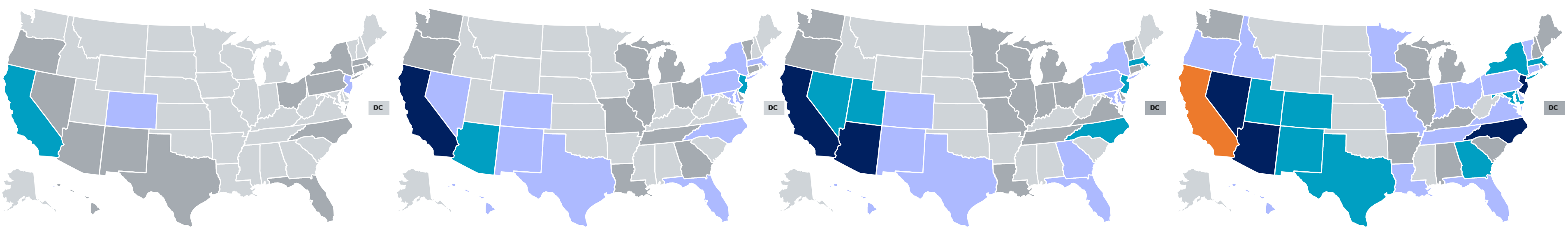
Sources: Company figures based on Q4 '16 (and previous) SEC filings by the respective companies.

Cumulative Solar

December 2010	December 2012	December 2014	December 2016
1.9 GW	6.4 GW	16.5 GW	34.7 GW



- The number of states with more than 100 MW-AC has grown from 3 in 2010 to 28 by the end of 2016.
- The number of states with more than 15 MW-AC has grown from 16 states in 2010 to 39 states and DC by the end of 2016.
- Despite the growth in the number of markets, more than half of the solar capacity in the United States is still installed in two states.

- >15,000 MW_{AC}
- >1,500 MW_{AC}
- >500 MW_{AC}
- >100 MW_{AC}
- >15 MW_{AC}

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Source: EIA, Electric Power Monthly (February 2017, February 2015).

List of Acronyms and Abbreviations

APAC	countries in Asia and Oceana, except China, India, and Japan
ARRA	American Recovery and Reinvestment Act of 2009
ASP	average selling price
BOS	balance-of-system
DG	distributed generation
FiT	feed-in-tariff
G&A	general and administrative expenses
kW	kilowatt
kWh	kilowatt-hour
LMI	low-to-moderate income
MW	megawatt
NEM	net energy metering
PCS	power controlling systems
PPA	power purchase agreement
PURPA	Public Utility Regulatory Policies Act
Q/Q	quarter over quarter
ROW	rest of world
SG&A	selling, general and administrative expenses
SI	systems integration
STH	solar thermal heating
SREC	solar renewable energy certificates
TTM	tech-to-market
TWh	terawatt-hours
USD	U.S. dollars
W	watt
WACC	weighted average cost of capital
y/y	year over year
YTD	year to date